Proyecto Fin de Carrera

Optimización Energética de una Central Térmica para su Operación Eficiente con un Sistema de Captura de CO_2 por Post-combustión

Un proyecto para la consecución del título de Ingeniería Industrial
Especialidad Tecnologías Energéticas

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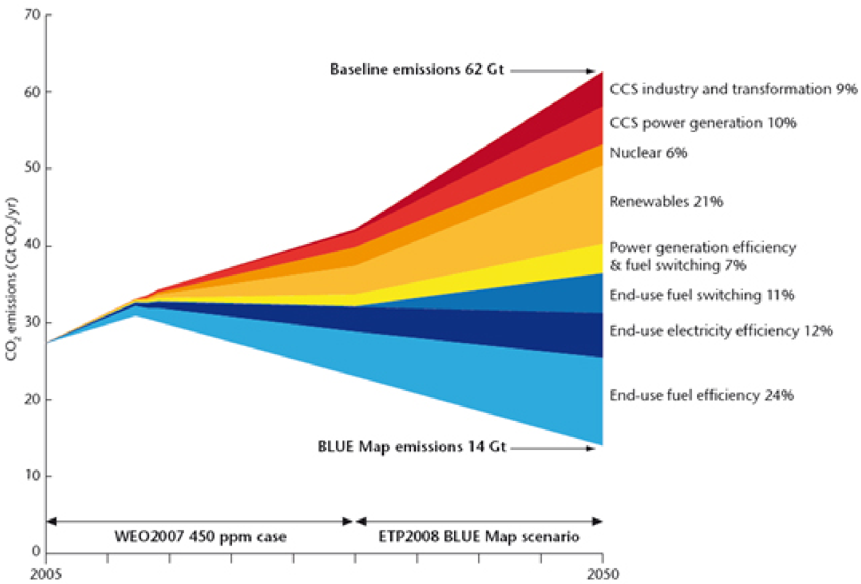
Resumen del Proyecto en Castellano

Introducción

El cambio climático es responsable del incremento gradual de la temperatura global. Detener este incremento y mantenerlo por debajo de 2,4°C será necesario para evitar cambios irreversibles en las condiciones climáticas del planeta. Existe un consenso creciente sobre la necesidad de reducir las emisiones de gases de efecto invernadero, principal causante del cambio climático, sin embargo, desde un enfoque realista la Agencia Internacional de la Energía (AIE) [19] detalla cómo actualmente los combustibles fósiles representan más del 80% de la energía primaria consumida en el mundo y cómo éstos seguirán siendo la principal fuente de energía durante las próximas décadas.

Ante este escenario, la Captura y Confinamiento de CO_2 (CCS) se convierte junto a la eficiencia energética, energías renovables y energía nuclear en una pieza clave dentro del conjunto de tecnologías necesarias para conseguir los ambiciosos objetivos de reducción de emisiones.



En el plan de la AIE para afrontar el Cambio Climático, la CCS asume cerca del 20% del objetivo de reducción de emisiones para 2050. Fuente: AIE [20]

La Captura y Confinamiento de CO_2 es un proceso por el cual el CO_2 generado en grandes focos de emisión tales como centrales térmicas, acerías o cementeras entre otros, es capturado y confinado indefinidamente para anular su efecto sobre la atmósfera.

Dentro de la Captura y Confinamiento de CO_2, la tecnología de post-combustión es considerada actualmente como la más prometedora para su implementación en centrales térmicas ya existentes y otras grandes instalaciones productoras de CO_2, puesto que se caracteriza por las menores modificaciones necesarias comparándola con las otras tecnologías de captura. Además presenta un elevado potencial para su optimización energética en un futuro próximo.

A lo largo de este proyecto se ha simulado una central térmica perteneciente al estado de la técnica y se ha optimizado para su operación junto con un sistema de captura por post-combustión. El software Ebsilon® Professional ha sido escogido para llevar a cabo la simulación.

Captura y Confinamiento de CO_2

CCS es la técnica mediante la cual parte del CO_2 generado en grandes focos de emisión es capturado, purificado, comprimido y posteriormente transportado para su posterior confinamiento en formaciones geológicas por un tiempo indefinido.

Esta técnica aprovecha otras tecnologías ya maduras como son el lavado de gases mediante productos químicos, el transporte de gases o la exploración de yacimientos de petróleo y gas, aplicándolas con un nuevo fin de protección ambiental, para reducir las emisiones de CO_2 de los combustibles fósiles y actuar como una tecnología puente entre el escenario actual y un futuro donde las renovables supondrán la fuente más importante de energía.

Captura de CO_2 Actualmente están siendo desarrolladas un número de tecnologías que podrían hacer comercialmente viable la CCS a gran escala para su implementación en centrales térmicas. Estas técnicas pueden ser agrupadas en tres categorías principales:

- **Oxi combustión** La combustión se realiza con un comburente de alto contenido en oxígeno y muy baja presencia de nitrógeno, de forma que la concentración de CO_2 en los gases resultantes sea muy elevada. Con ello se facilita la separación posterior, puesto que la composición de los gases de la combustión es casi en su totalidad vapor de agua y CO_2. El agua es separada y las impurezas restantes son extraídas para obtener una corriente de CO_2 de alta pureza lista para su compresión y transporte.

  Una de las desventajas de este método son los altos requerimientos energéticos del proceso de separación del oxígeno del aire. Las altas temperaturas alcanzadas al quemar combustibles con oxigeno - demasiado elevadas para las calderas convencionales - son otro reto para esta tecnología. Una solución es la recirculación de parte de los gases de la combustión.

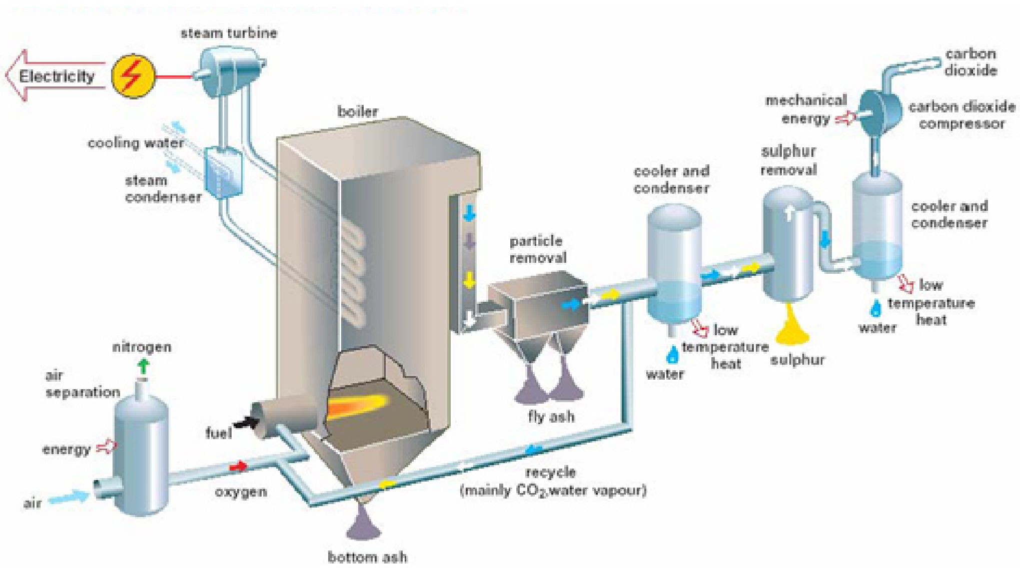


Diagrama de oxi combustión, también llamada combustión en O2/CO2. Fuente: Vattenfall

- **Pre combustión** Se trata de separar el CO_2 a la salida del gasificador, antes de que el gas de síntesis entre en la turbina de gas. Esta categoría es aplicable únicamente a nuevas centrales térmicas de tipo Gasificación Integrada con Ciclo Combinado (GICC). Es la tecnología que presenta los menores costes de captura.

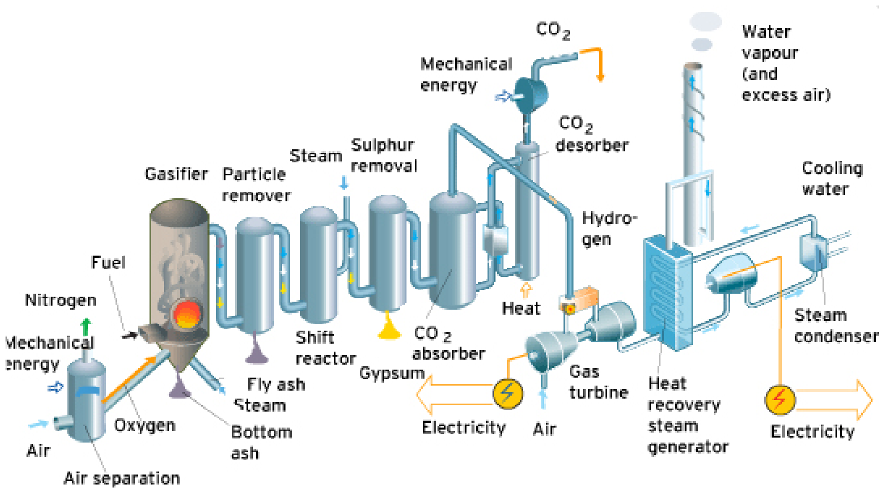


Diagrama de captura por pre combustión, aplicado en centrales tipo GICC. Fuente: Vattenfall

- **Post combustión** Es un sistema de captura de CO_2 basado en el lavado de gases con productos químicos mediante procesos de absorción/desabsorción química. El CO_2 es absorbido en un disolvente en la columna de lavado, posteriormente el disolvente es regenerado en la columna de desabsorción liberandose el CO_2 y obteniéndose una corriente de alta pureza en CO_2. Esta categoría es la más apropiada para su aplicación en centrales térmicas ya existentes pero requiere altos consumos de energía y por tanto el rendimiento de la central cae de forma significativa.

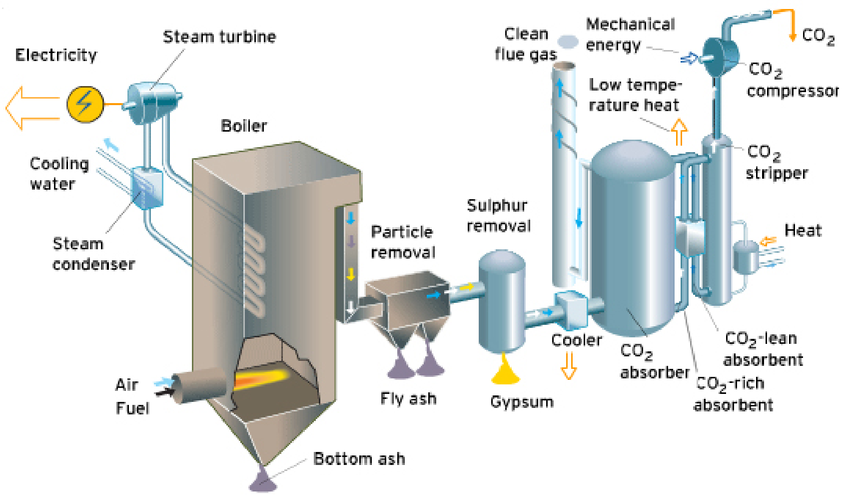


Diagrama de captura por post combustión. Es la categoría que menores modificaciones requiere en plantas convencionales. Fuente: Vattenfall

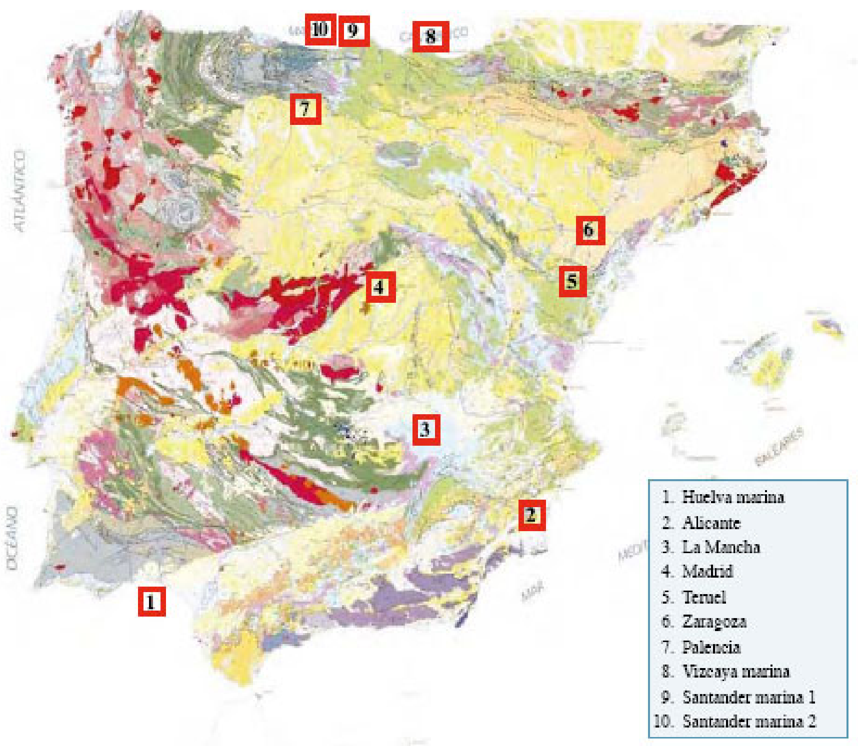
Compresión y transporte de CO_2 El CO_2 ha de ser comprimido previamente a su transporte para reducir su volumen. En estado supercrítico el CO_2 ocupa un volumen del 0,2% en comparación con el volumen en condiciones ambientales. La presión de transporte depende de las características del lugar de almacenamiento final así como de las distancias de transporte por gasoducto. El CO_2 es generalmente comprimido a presión supercrítica entre 100 y 150 bar.

El transporte de CO_2 puede realizarse por gasoductos, buques gaseros, o por tierra mediante contenedores cisterna. El transporte de CO_2 se beneficia de la experiencia adquirida en el transporte de gas natural y otros combustibles gaseosos gracias a sus semejantes características.

Almacenamiento de CO_2 Existen dos alternativas para el confinamiento permanente de CO_2: formaciones geológicas y almacenamiento marino.

- El almacenamiento marino consiste en inyectar el CO_2 en simas profundas en el océano. El agua con CO_2 disuelto es más densa que el agua de mar y se mantiene estable durante cientos de años, formando ”lagos” en el fondo marino. Esta opción ha sido casi totalmente descartada por la falta de conocimiento y las incertidumbres que genera.

- El confinamiento geológico tiene lugar en formaciones que aseguren que el CO_2 se mantenga sin fugas durante miles de años. Hay tres tipos de formaciones que pueden ser utilizadas para confinar CO_2 y que presentan un alto potencial en capacidad de almacenamiento: Acuíferos marinos, yacimientos agotados de petróleo y gas y betas de carbón no extraíbles.



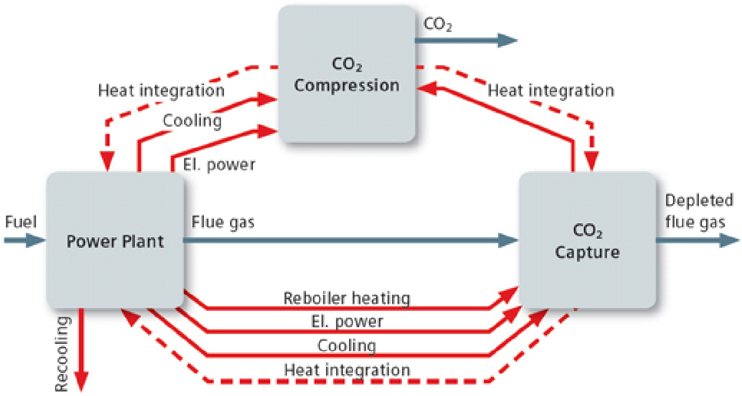
Mapa de posibles localizaciones de formaciones geológicas apropiadas para el confinamiento geológico de CO_2 en España. Fuente: Fundación para Estudios sobre la Energía

Simulación de la Central Térmica y Planta de Captura de CO_2

Los capítulos 2, 3 y 4 de este proyecto tratan aspectos teóricos sobre centrales térmicas y la tecnología de captura y almacenamiento de CO_2, post combustión en concreto. Estos capítulos ponen de manifiesto las ventajas de la captura de CO_2 pero también las grandes cantidades de energía necesarias y el efecto negativo que este proceso tiene sobre el rendimiento neto de la central.

Estos importantes requerimientos de energía pueden ser reducidos aplicando un doble enfoque: en primer lugar, la optimización del proceso de captura y compresión para una operación más eficiente. En segundo lugar, la integración energética de la central térmica con la planta de captura para la recuperación de calores residuales.

Esta segunda opción es el objeto de este proyecto. Los siguientes capítulos están dedicados al estudio y comparación de tres casos. Como caso de referencia, en el capítulo 7 se ha simulado una central térmica de vanguardia. A continuación, en el capítulo 8, se añadió una planta de captura y compresión de CO_2 convencional para analizar la caída de rendimiento y otros efectos de la planta de captura sobre la central térmica. Por último, en una serie de casos dentro del capítulo 9, se estudiaron posibles integraciones energéticas y utilización de calores residuales para aumentar la eficiencia de la central térmica con captura de CO_2.



Flujos de energía entre las principales áreas de una central térmica con captura de CO_2 integrada. Fuente: Siemens [21]

Los casos de optimización analizados fueron los siguientes:

Integración I: Precalentamiento del aire de combustión mediante calor residual proveniente de la columna de desabsorción en el proceso de captura de CO_2 (ver figura 9.6).

Integración II: Es posible utilizar parte del calor residual para precalentar agua en el ciclo de agua/vapor en la línea de precalentadores de baja presión LP1, LP2, LP3 y LP4. Así, es posible eliminar el primer precalentador y reducir el incremento de temperatura de LP2 añadiendo un intercambiador agua-agua para transferir el calor residual de la columna de desabsorción y el evacuado por el sistema de refrigeración del compresor. De este modo se reduce el sangrado de vapor necesario de la turbina de baja presión y se incrementa la potencia neta de la central (ver figura 9.12).

Integración III: Al precalentar el aire de combustión con calor residual del proceso de captura de CO_2, el aire llega al precalentador de aire a una temperatura más elevada. Ahora, es posible utilizar parte de la energía remanente en los gases de la combustión no sólo para precalentar el aire sino para además incrementar la temperatura de una extracción de agua de la línea de baja presión, reduciendo así el sangrado necesario para operar los precalentadores de agua de baja presión (ver figura 9.19).

Integración IV: Uso de la nueva tecnología de onda de choque para la compresión del CO_2. El estado de la técnica en compresión de CO_2 es el uso de compresores centrífugos de multieje, que tratan de seguir la línea de compresión isoterma y se acercan así al consumo mínimo. Estos compresores necesitan alrededor de cinco etapas con refrigeración intermedia para alcanzar presiones supercríticas de CO_2 (entre 100 y 150 bar). El CO_2 alcanza temperaturas cercanas a los 100°C tras cada etapa de compresión. El sistema de refrigeración evacua este calor haciendo circular un fluido refrigerante que alcanza temperaturas cercanas a 70°C. Mayores temperaturas podrían dañar el compresor (Ver figura 9.24).

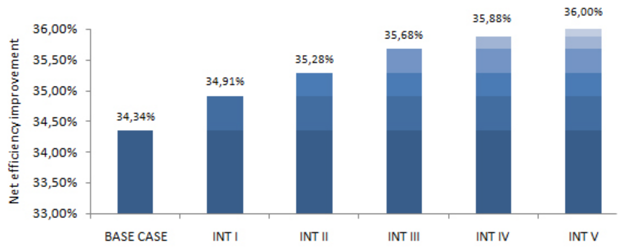
Una nueva tecnología de compresión en estado de validación, desarrollada por la compañía estadounidense Ramgen®, promete elevados ratios de compresión y la posibilidad de elevar grandes flujos de CO_2 a presión de transporte en únicamente dos etapas. Las temperaturas que alcanza el CO_2 después de cada etapa son cercanas a 270°C. Esto permitiría un sistema de refrigeración donde el fluido refrigerador, que debería ser un aceite térmico o agua presurizada, podría alcanzar temperaturas mayores a 200°C. Esta elevada temperatura del calor evacuado del sistema de compresión hace que sea posible ceder parte de esta energía al ciclo de agua/vapor incluso en la línea de precalentadores de alta presión.

La cuarta integración por tanto aplica esta nueva tecnología de compresión y tras detallado estudio se concluyó que la alternativa óptima en términos de eficiencia neta de la central es la adición de un intercambiador agua/aceite antes del desaireador y otro en la línea de precalentamiento de agua de baja presión.

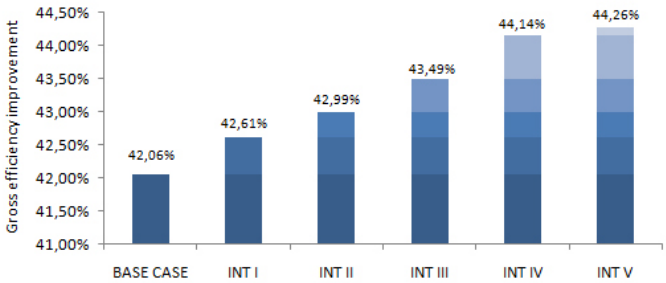
Integración V: Para regenerar el disolvente rico en CO_2 es necesario el uso de grandes cantidades de vapor. Por una serie de requerimientos del proceso de desabsorción del disolvente y otros factores a tener en cuenta, el vapor es extraído habitualmente del conducto de cruce de la etapa intermedia a la etapa de baja presión en la turbina. Este vapor se encuentra a temperaturas más elevadas que la necesaria para la regeneración. Por tanto, si se añade un intercambiador que transfiera parte de la energía contenida en el flujo extraído hacia el ciclo de agua/vapor, es posible incrementar discretamente la eficiencia de la central.

Una vez concluido el proceso de integración energética, la central térmica con captura de CO_2 por post combustión queda simulada en la figura 9.27.

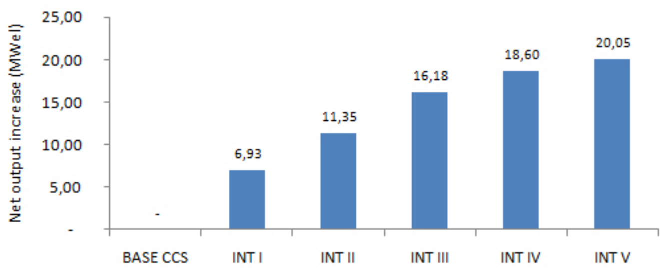
A continuación se muestra una serie gráficas con los principales resultados de este estudio:



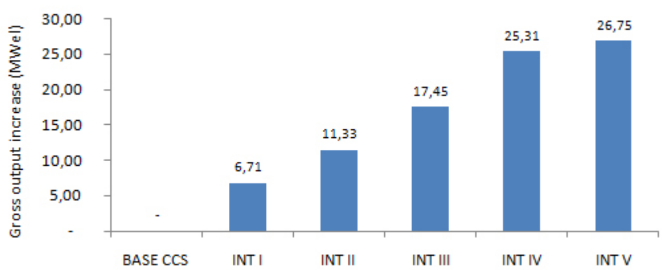
Optimización del rendimiento neto de la central después de las integraciones propuestas. La central en estudio tiene un rendimiento neto del 45,9% sin proceso de captura.



Optimización del rendimiento bruto de la central después de las integraciones propuestas. La central en estudio tiene un rendimiento bruto del 49,5% sin proceso de captura.



Incremento de la potencia neta después de las integraciones propuestas. La central en estudio tiene una potencia neta de 556 MW_{el} sin proceso de captura y 414 MW_{el} en el caso CCS base.



Incremento de la potencia bruta después de las integraciones propuestas. La central en estudio tiene una potencia bruta de 600 MW_{el} sin proceso de captura y 509 MW_{el} en el caso CCS base.

Conclusiones

El proceso de captura por post combustión es actualmente la tecnología más prometedora dentro de las diferentes opciones en CCS. A pesar de ello, todavía se enfrenta a una serie de retos: incrementar la escala hasta los volúmenes de centrales comerciales y reducir el consumo energético para minimizar la penalización sobre el rendimiento neto de la central.

Los resultados de este estudio muestran como al instalar un sistema de captura por post combustión, la extracción de vapor y energía eléctrica necesarias hacen caer la potencia neta de la central 142 MW_{el} desde 556 MW_{el} hasta los 414 MW_{el}. Esto supone una caída de rendimiento neto del 45,9% a un 34,2%, es decir, una caída cercana a 12 puntos porcentuales.

Mediante la integración energética realizada en este estudio es posible reducir esta penalización casi un 15% hasta tener una caída de rendimiento neto de 10 puntos porcentuales. Después del proceso de integración, la central llega a producir hasta 20 MW_{el} más comparándola con el caso de central térmica con captura no integrada.

Master Thesis

Energetic Optimization of a Steam Cycle Power Plant for an Efficient Operation of a Post-combustion CO_2 Capture Plant

ausgeführt zum Zwecke der Erlangung des akademischen Grades eines Master of Science
unter Anleitung von

Proj.Ass. Dipl.-Ing. Sebastian POSCH
Univ.Prof. Dipl.-Ing. Dr.tech. Markus HAIDER

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Abstract

The post-combustion separation technology (PCC) is one out of three main types of CO_2 separation. PCC is mainly characterized by the fact that the intervention in the conventional power plant process is the smallest one compared to the other capture technologies. Furthermore post-combustion can be applied to the conventional power plant process as well as to a CO_2-producing industry plant. Therefore for Austria's point of view, PCC is the most promising technology.

A state-of-art coal-fired power plant retrofitted with a post-combustion CO_2 capture system was modeled with the process simulation tool EBSILON® Professional. The drastic CO_2 emissions reduction comes together with a significant net efficiency penalty.

A series of simulations were carried out to find what further opportunity exists to reduce the impact of the capture system on net efficiency via astute integration of both plants. Within this thesis several heat integration measures were implemented and their results compared with the reference non integrated retrofitted power plant, showing a significant efficiency penalty reduction after heat integration.

Resumen

La separación por post-combustión (PCC) es una de las tres principales tecnologías para la Captura y Confinamiento de CO_2. Esta técnica se caracteriza por poder ser implementada en centrales térmicas convencionales, requiriendo en ellas el mínimo número de modificaciones comparado con las demás tecnologías de captura. Más allá, esta tecnología puede ser aplicada también a otras grandes industrias emisoras de CO_2. De este modo, la separación de CO_2 por post-combustión es, desde el punto de vista austriaco, la opción más prometedora.

La substancial reducción de emisiones de CO_2 que este sistema posibilita, tiene como consecuencia directa una importante caída en el rendimiento neto de la central. A lo largo de este proyecto, llevado a cabo mediante el software comercial EBSILON® Professional, se ha simulado una central térmica de vanguardia alimentada por combustible carbón pulverizado, para su operación conjunta con un sistema de captura por post-combustión.

La serie de simulaciones llevadas a cabo han demostrado como, a través de una astuta integración energética entre ambas; planta de captura y central térmica, es posible reducir la caída de rendimiento de una forma significativa y con ello los propios costes de reducción de emisiones.

Contents

1. Introduction

Climate change is one of this century's most serious challenges. And greenhouse effect is the main responsible, causing a gradual increase in the average planet temperatures. The Intergovernmental Panel on Climate Change [29] has remarked that keeping the rise in average total temperature below 2,4°C is the only way to avoid irreversible changes.

Consensus is growing among researchers, policy makers and business leaders that concerted action will be needed to tackle rising greenhouse gas emissions. CO_2 is the greenhouse gas that makes the most significant contribution towards the greenhouse effect and therefore is the first target[1]. The discussion is now turning to the practical issues of where and how emissions reduction can best be achieved, at what costs, and over what period of time. And to find the right answer, it will only be possible from a rigorous and realistic analysis of the current global trends in energy supply and consumption.

Fossil fuels are the world's vital source of energy and will remain so for many years to come even under the most optimistic scenarios of low carbon technology development and deployment[2]. With a strong expected growth in the world population from 6,5 billion in 2006 to 8,2 billions in 2030 and a rate of economic growth assumed to average 3,3% per year over the period 2006 to 2030, the expected increase on the global energy demand becomes a reality. Moreover, the need to secure supply of a reliable and affordable energy and the long lasting resources of fossil fuels (especially coal) will lead not only to maintain but to an increase in oil, gas and coal[3] demand over the next decades. According to the *IEA Energy Technology Perspectives 2008*, this scenario will lead to an increase on the energy sector CO_2 emissions over 130% above 2005 levels, in the absence of new policies [29].

Carbon Capture and Storage: A Key Abatement Option

In the *Technology Roadmap for Carbon Capture* and Storage, IEA assesses strategies for reducing GHGs emissions by 50% by 2050 compared to levels off 2005 (see figure 1.1). This report concludes that CCS will have to contribute by 20% of the total reductions to achieve stabilization of the atmospheric level of GHGs in the most cost effective manner.

Mitigating emissions without CCS technologies, would suppose an increase in overall cost of 70%. Carbon capture and storage is therefore an essential part of the portfolio of solutions needed to achieve the global emissions reduction target [20].

Despite the main role that carbon capture and storage technology will play in this scenario, it is not ready yet for large scale and commercial application. To establish CCS as a mature and reliable technology, exhaustive research and development efforts are being done in all three main technical fields involving CCS. CO_2 transport technology benefits from the wide experience gained in gas transportation both by pipeline and by ship. The storage field, although is still in validation phase, involves similar technology to that employed by oil and gas industry for exploration and production of hydrocarbons. Finally, carbon capture still involves significant additional equipment and high energy-intensive processes. Thus, within the three areas, carbon capture has the major impact on energy consumption and economic investment, representing from 70 to 80% of the total costs of a

[1] The BLUE Map scenario, established by the IEA, represents a guideline to reduce GHGs emissions 50% by 2050 compared with levels of 2005.

[2] According to the IEA, today fossil fuels represent more than 80% of the global primary energy supply and will remain essential in the world's primary energy mix accounting 80% by 2030, down slightly on today.

[3] In the IEA World Energy Outlook 2008 coal continues to account for about half of fuel needs for power generation by 2030.

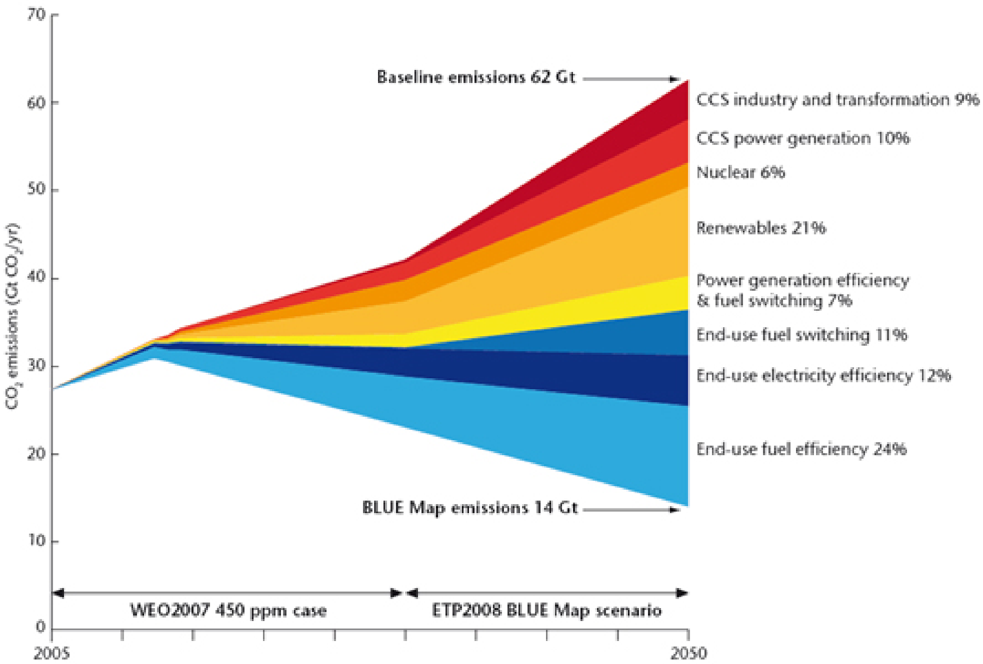

Figure 1.1: CCS reduction up to 20% in the lowest-cost mitigation scenario for 2050

carbon capture, transport and storage system [5]. Scaling up carbon capture, from pilot plants (less than 10MWel) to large commercial power plants (more than 100MWel) [9], and reducing overall efficiency penalty caused by the capture process are the two central challenges facing CCS.

Within CCS, post-combustion separation is one of the carbon capture most promising techniques [5]. This technology is mainly characterized by small modifications in the power plant and the possibility for retrofitting existing power plants and large emitters as iron or concrete industry. Particularly for post-combustion, extensive integration between the power plant and the capture plant shows one of the highest potentials to reduce efficiency penalty [30]. This work is an attempt to show how a high integrated process can optimize overall efficiency of a pulverized coal-fired power plant operating with a post-combustion capture plant.

For this study a state-of-art coal-fired power plant has been chosen. Developed by a joint research of plant constructors and operators, the Reference Power Plant North Rhine Westphalia (RPP NRW) [31] is a concept study for an ultra-supercritical 600MW single unit designed for inland location and with net efficiency of 46%.

The alternative software packages for the simulation were ASPEN Plus® and EBSILON® Professional 8.0. The first is designed to simulate chemical processes while the latter is optimal for energy and mass balancing of power plant processes. Since the aim of this study was the power plant integration, EBSILON® Professional 8.0 was selected.

2. Steam Cycle Power Plants

This chapter revises the basic characteristics and design of steam power plants. Starting from a theoretical approach it will reach the state-of-art process and equipment and finally, an outlook on the future development of steam power plants.

2.1. The Rankine Cycle

Since the beginning of thermodynamics as a modern science, with the Carnot cycle as the highest efficiency hypothetical heat engine, Rankine cycle was conceived and readily accepted as the closest real solution to Carnot's cycle. Therefore it became the standard for steam power plants and remains so today.

This section is focused to the analysis of the Rankine cycle, from its simplest ideal form to its more complex application present today in the state-of-art steam power plants. For its realization, the book Powerplant Technology of M.M El-Wakil [8] has been followed, as well as other relevant literature.

2.1.1. The Ideal Rankine Cycle

Rankine cycle is a two-phase cycle usually represented by a *T-S* diagram and its most simplified flow diagram, both shown in the figure 2.1. Cycle *1-2-3-4-B-1* is a saturated Rankine cycle with saturated steam entering the turbine,while *1'-2'-3-4-B-1'* represents a superheat Rankine cycle.

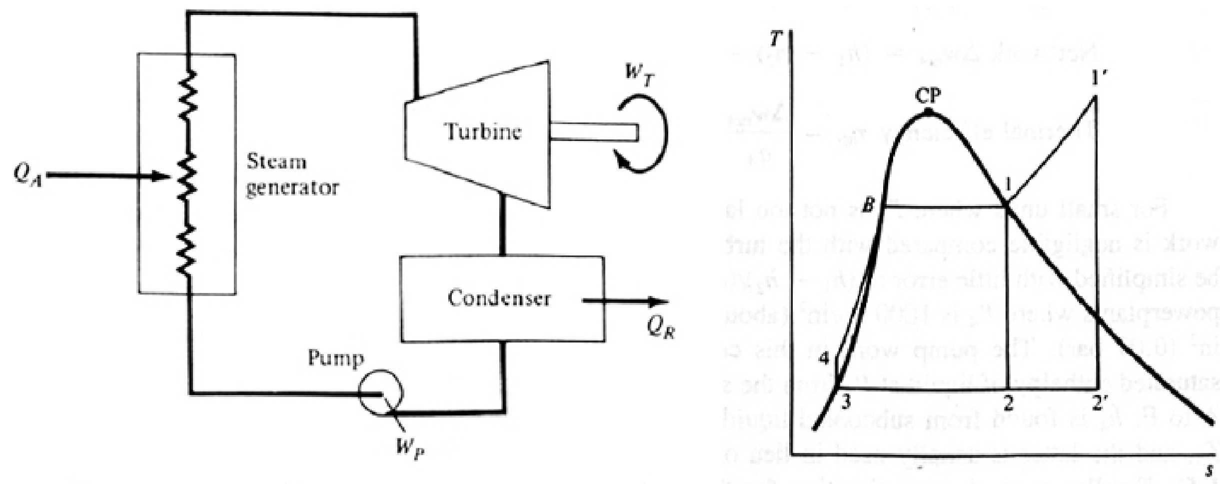

Figure 2.1: Ideal Rankine cycle flow diagram and T-s diagram [8]

Both cycles are ideally reversible and have the following processes:

- ***1-2 or 1'-2'***: adiabatic reversible expansion through the turbine. The exhaust vapor is usually in the two phase region.
- ***2-3 or 2'-3***: constant temperature and pressure heat rejection in the condenser.

- ***3-4:*** adiabatic reversible compression by the feedwater pump of saturated liquid at the condenser pressure to subcooled liquid at the steam generator pressure.
- ***4-1 or 4-1'***: Constant pressure heat addition in the steam generator to saturated steam conditions in *4-1* or superheated steam in *4-1'*

The line *4-B* represents bringing the subcooled liquid to a saturated liquid. This heat addition takes place in the economizer. The portion *B-1*, the phase change from saturated liquid to saturated steam, takes place in the boiler or evaporator. For superheat cycles the additional heat input at constant pressure represented by *1-1'* is carried out within the steam generator by the superheater sections. These idealized processes are internally reversible without pressure losses in the piping, inefficiencies in turbine or in the pump, achieving the thermal efficiency shown in equation (2.1). The superheat cycle efficiency *1'-2'-3-4-B-1'* can be calculated the same way using *1'* instead of *1*.

$$\eta_{th} = \frac{\Delta W_{net}}{q_A} = \frac{(h_2 - h_1) - (h_4 - h_3)}{(h_1 - h_4)} \tag{2.1}$$

2.1.2. The Externally Irreversible Rankine Cycle

External irreversibility is the result of the temperature differences between the primary heat source, the combustion gases from the steam generator furnace, and the working fluid; and the temperature differences between the condensing working fluid and the cooling medium.

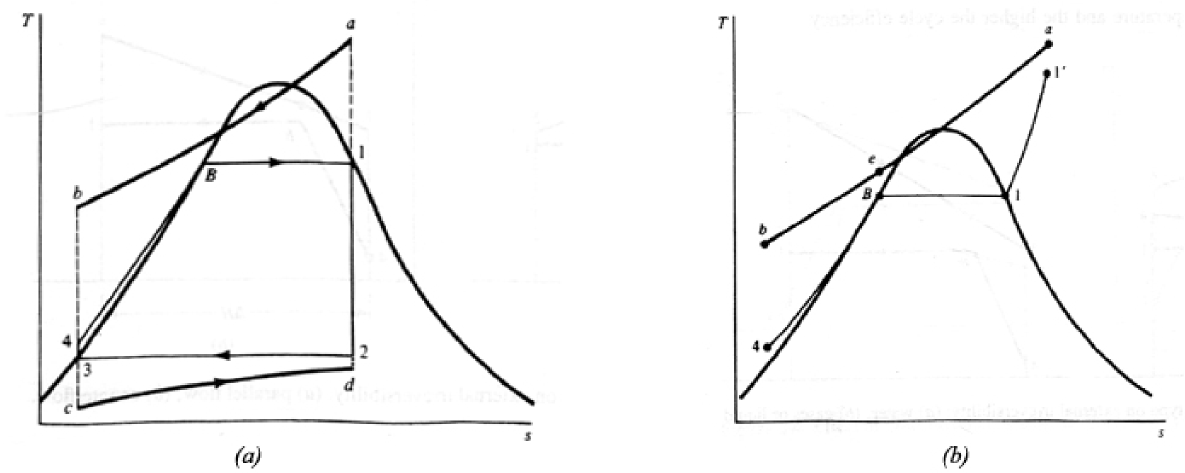

Figure 2.2: (a) External irreversibility with Rankine cycle. (b) External irreversibility with superheat Rankine cycle [8]

Figure 2.2a represents with lines *ab* and *cd*, high temperature heat source and the cooling fluid. High average temperature differences between lines *ab*, *cd* and the working fluid, result in small and inexpensive steam generator, but also lead to high irreversibility and, hence, reduction in plant efficiency.

Superheat

There are a few possibilities to improve overall efficiency by reducing temperature differences between working fluid and the cooling system (see 2.2a). In contrast, irreversibility in the case of combustion gases can be reduced by the use of superheated steam. By heating up the working fluid to *1'* the average temperature difference between *ae* and *B-1-1'*, figure 2.2b, decreases. Thus, superheating would improve the cycle thermal efficiency. Moreover, superheated steam is necessary in real installations, due to the substantial damages that a steam with significant levels of moisture would produce to the blades of the turbine.

Reheat

An additional improvement in cycle efficiency with fossil fueled power plants can be achieved by the use of reheat. Figure 2.3 shows the simplified flow and T-s diagram of a Rankine cycle with one reheat stage.

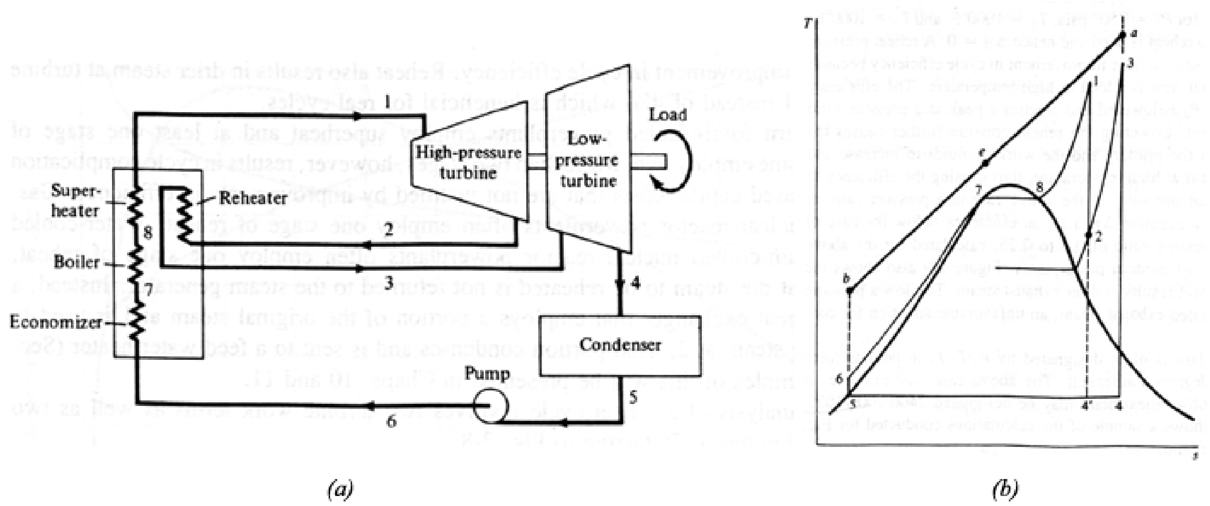

Figure 2.3: (a) Schematic of a Rankine cycle with superheat and reheat and (b) its respective T-s diagram [8]

Reheat allows a second heat addition, resulting in an increase of the average temperature in which the heat is added to the working fluid and as a consequence an increase in the cycle efficiency. As in superheat, for practical application, reheat result also beneficial due to the drier steam conditions achieved at the turbine exhaust.

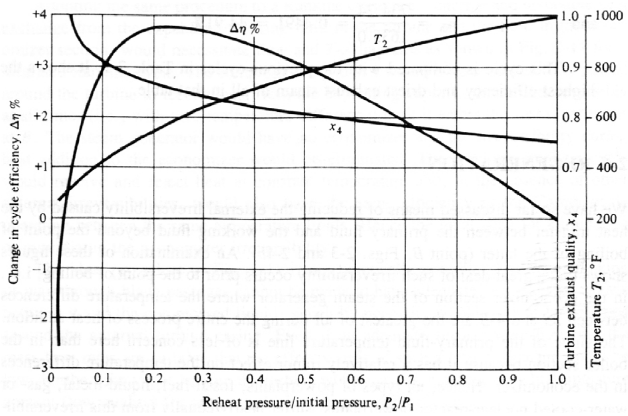

Figure 2.4: Effect of reheat pressure ratio on efficiency, High pressure turbine exit temperature, and low pressure trubine exit quality [8]

The reheat pressure P_2 affects the cycle efficiency as it is shown in the figure 2.4. The efficiency improves as the reheat pressure P_2 is lowered and reaches a maximum at a pressure ratio P_2/P_1 between 20 and 25 percent, where P_1 is the life steam pressure.

Regeneration

Regeneration represents a way to reduce average temperature differences and thus inefficiencies that occur prior to the boiling point in the economizer section, between lines *be* and *4B* in figure 2.2b. The irreversibility could be eliminated if the feeding water enters the generator at *B* rather than at point *4*.

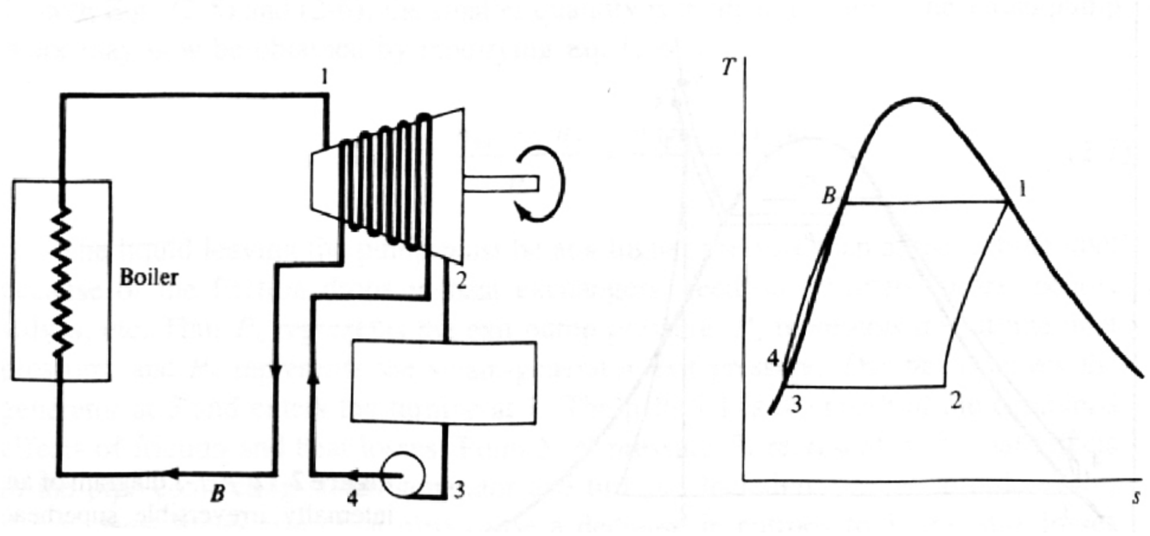

Figure 2.5: Ideal regeneration of a Rankine cycle [8]

Figure 2.1 shows the ideal regeneration of a Rankine cycle, resulting what is called carnotization of the cycle. The ideal regeneration of a Rankine cycle would suppose continuous heat transference between the expanding steam and the feedwater line without bleeds. Transferring such amount of heat without the use of the steam latent heat would require a turbine shell with enormous surfaces between the expanding fluid and feedwater to enable the same heat transference. For this reason, ideal regeneration is not technically feasible. In practice, the compressed feedwater is heated in a finite number of steps by vapor bled from the turbine at selected stages, rather than continuously. Because the finite number of heating stages, the feedwater enters the steam generator at a point below *B*, making necessary an economizer section, tough one much smaller than the required without regeneration.

Regeneration results in a reduction of power output but in a significant improvement in the overall thermal efficiency (η_{th}). For this reason, modern large steam power plants use between five and eight feedwater heating stages [8]. Higher number of stages is uneconomic since the efficiency increase due to an additional preheater becomes smaller.

There are three types of feedwater heaters in use, these are:

- **Open or direct-contact feedwater heaters**

  In the open or direct-contact type feedwater heater the extracted steam is mixed directly with the incoming subcooled feedwater to produce saturated water at the extraction pressure. The pressure at *6-7* in figure 2.6 can be not higher than the extraction steam pressure at *3* in order to avoid reverse flow.

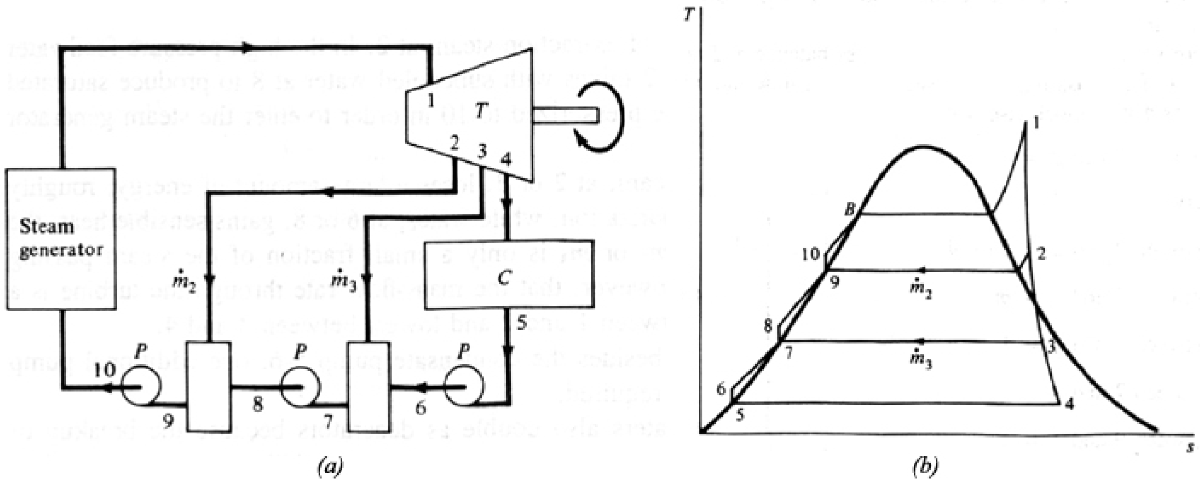

Figure 2.6: (a) Schematic flow and (b) *T-s* diagrams of a nonideal superheat Rankine cycle with two open-type feedwater heaters [8]

Open-type feedwater heaters are currently called deaereators, because the mixing process increase the surface area and liberates noncondensible gases (air, O_2, H_2 or CO_2) that can be vented to the atmosphere.

Open feedwater heaters require as many additional pumps as there are open heaters. Each of these pumps work with nearly full flow causing operational problems and adding complexity and initial investment to the power plant. Therefore, in general only one open feedwater heater is used, working additionally as deaerator.

- **Closed type feedwater heaters with drains cascaded backward**

Closed heaters are the simplest and most used in power plants even when they show greater loss of availability. In this case, feedwater flows through the tubes of the heat exchanger and the steam extraction condenses in the shell. This condensate is usually fed back to the next lower pressure feedwater heater.

In figure 2.7 is depicted how feedwater temperature at *7* cannot reach the inlet bled steam temperature at *3*. The terminal temperature difference (TTD) is then defined for closed heat exchangers in equation (2.2). *TTD* values depend on the design of the heat exchanger. Low-pressure heaters have positive value of the order of 3°C. Smaller values increase plant efficiency but require larger and more expensive heat exchangers. A closed heater that receives saturated or wet steam can have a drain cooler usually called subcooler. Last heater feeds back the condenser, process *9-10*.

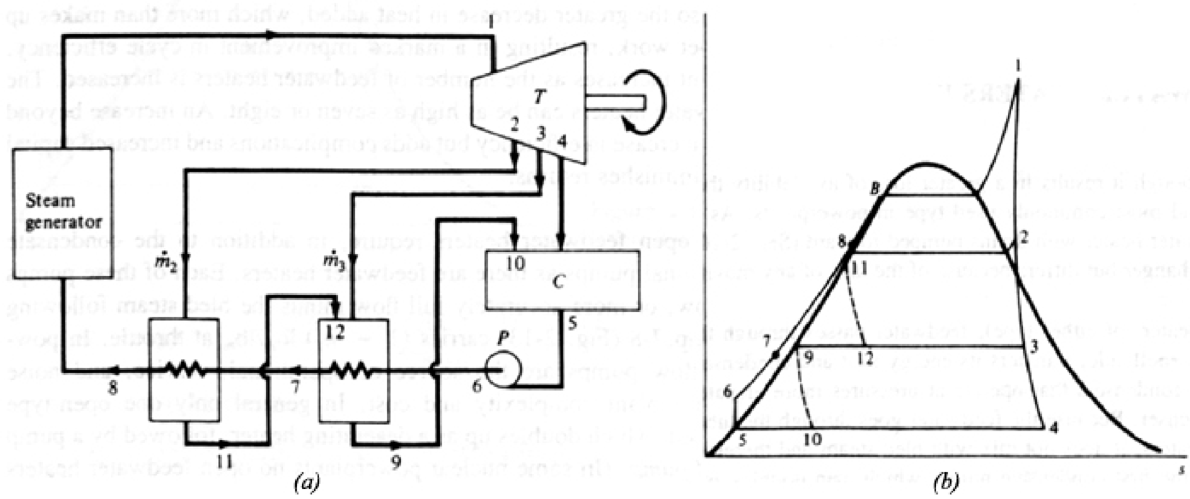

Figure 2.7: Schematic flow and (B) *T-s* diagrams of a nonideal superheat Rankine cycle with two closed-type feedwater heaters with drains cascaded backward [8]

High pressure feedwater heaters receive superheated steam. For this reason feedwater can leave the preheater at higher temperatures than the steam temperature at the saturation pressure. Equation (2.2) tell us that the TTD values can therefore be negative. Current values are between 0°C and -3°C. The heater is physically composed of a desuperheater section, a condensing section, and a drain cooler section.

$$TTD = t_{sat,bled} - t_{fw,exit} = t_3 - t_7 \approx 3°C \tag{2.2}$$

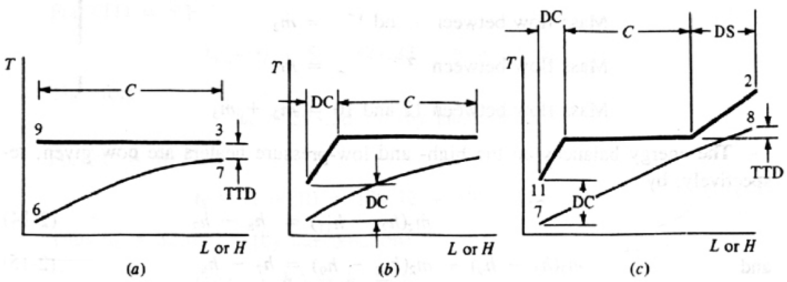

Figure 2.8: T-h diagrams of (a) and (b) low pressure and (c) high pressure feedwater heaters. TTD=Terminal temperature difference, DS=desuperheater, C=condenser [8]

In summary there are four types of closed feedwater heaters: Condenser, condenser-subcooler, desuperheater-condenser-subcooler and desuperheater-condenser.

- **Closed type feedwater heaters with drains pumped forward**

This type of regeneration avoids throttling losses but adds complexity and investment to the power plant because of the introduction of a small pump (see figure 2.9). In this case the drain, instead of be cascaded backwards, is pumped forward. However, unlike the open feedwater heater, the drain pump is a low-capacity pump only working with the extraction flow.

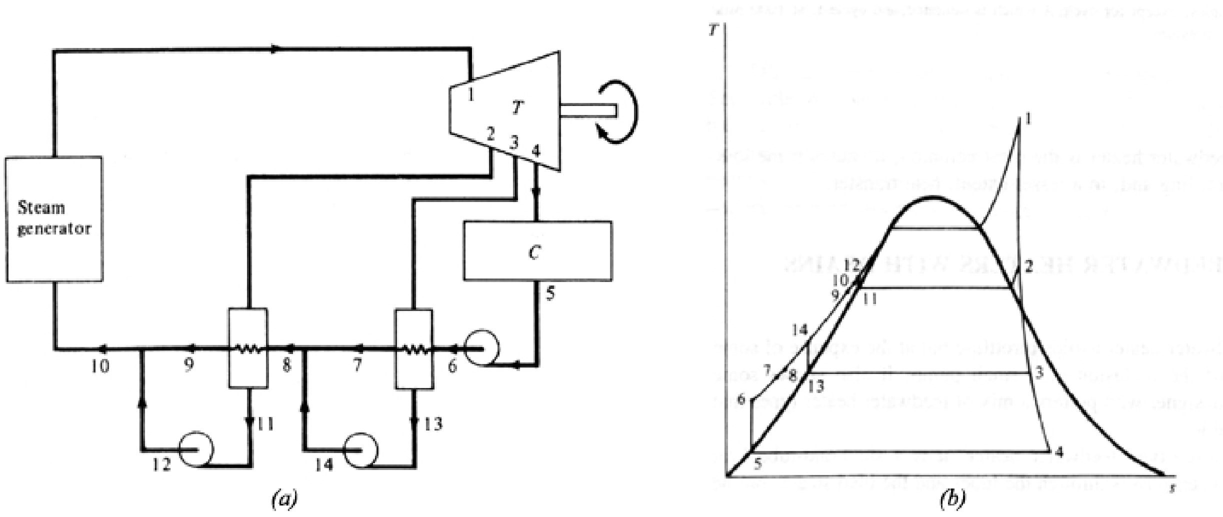

Figure 2.9: (a)Schematic flow and (b) T-s diagrams of a nonideal superheat Rankine cycle with two closed-type feedwater heaters with drains pumped forward [8]

Other advantage of these feedwater heaters is that, when used as the lowest pressure heater, prevent the throttling of the combined cascaded flows to the condenser, where the rest of energy contained in that flow is lost to the environment. These types of feedwater heaters show better performance without subcooling section to allow maximal temperatures up in the injection point.

Placement of feedwater heaters Feedwater heaters should be located at the position where the maximum increase in efficiency is achieved. In other words, pressures at which steam is to be bled from the turbine maximize thermal efficiency. As indicated previously, page 6, the role of feedwater heaters is to reduce the temperature difference between the hot gases from the combustion and the feedwater entering the steam generator, what results in a reduction of irreversibility and hence in an efficiency increase.

If we assume for simplicity, that only one feedwater heater is used and situated in a temperature T_x between the boiler temperature T_B and the condenser temperature T_C, the heat transfers to the feedwater heater will be caused by ΔT_{B-x} and ΔT_{x-C}. Thus, from an irreversibility point of view, the optimal T_x will be the one that minimizes both temperature differences. Therefore, optimal extraction pressure will be the saturation pressure at the temperature T_x, that is half way between T_B and T_C. Then, for n feedwater heaters the optimum temperature rise per heater is given by eq (2.3). If the turbine is not ideal, the exact turbine expansion line must be first determined to find the bled steam inlet temperatures and enthalpies.

$$\Delta T_{opt} = \frac{T_B - T_C}{n+1} \tag{2.3}$$

In actual power plants feedwater heaters are not necessarily located at their optimum positions since other considerations may dictate the exact positions. These can be technical considerations, such as the best point for deaeration, the existence of convenient points where extractions can be done like the crossover pipe between turbines or the steam outlet at the reheat pressure, design of the turbine casing and other considerations.

Summary The choice of feedwater heaters depends on many factors, including energetic optimization, costs, practical considerations and so on. However, some designs are common in large power plants: first, one open type heater working also as a deaerator; Second, closed heaters cascaded backwards before and after the deaerator with superheating and subcooling sections in high pressure stages, and subcooling in low pressure heaters. And last, one closed heater with drain pumped forward in the lowest preheating stage to prevent energy losses in the condenser [8].

2.1.3. The Internaly Irreversible Rankine Cycle

Internal irreversibility is the result of fluid friction, throttling and mixing. The most important losses take place in turbines, pumps and pressure losses in heat exchangers and piping. The irreversible losses in the turbine are represented by the turbine isentropic efficiency (η_t) in equation (2.4). State-of-art turbines present high efficiencies, up to 90% in design conditions.

$$\eta_t = \frac{(h_1 - h_2)}{(h_1 - h_{2s})} \tag{2.4}$$

Pump irreversibility is also represented with the pump isentropic efficiency (η_p) given by the ratio of the ideal work to the real work (2.5).

$$\eta_p = \frac{(h_{4s} - h_3)}{(h_4 - h_3)} \tag{2.5}$$

2.1.4. Efficiency and Heat Rate

Thermal efficiency is the ratio of the net work to the heat added to the cycle power plant. To calculate the real efficiency, all auxiliaries and nonidealities must have been taken into account. These are, nonidealities in turbines, pumps, friction, heat transfer, throttling, etc.

Gross efficiency is based on the gross power output of the turbine generator and net efficiency is calculated based on the gross power output minus the tapped power for the internal operation of the power plant. Efficiency is considered a measure of the economy of the power plant. In addition, another parameter is used by designers, called the *heat rate* (HR). Heat rate is the amount of heat added to produce a unit of work. Heat rate is inversely proportional to the efficiency.

2.1.5. The Supercritical Pressure Cycle

In figure 2.10 the water is pumped to a pressure beyond the critical pressure of the vapour (221 bar). Feedwater curve shows gradual change in temperature and density but not a two-phase stage. From the irreversibility approach, supercritical pressure cycle receives more energy at higher temperatures than a subcritical with same steam conditions at the turbine inlet. Therefore, thermal efficiency increases. Since there is no two-phase stage and water density varies gradually, supercritical steam cycles use *once trough steam generators* instead of the common drum type.

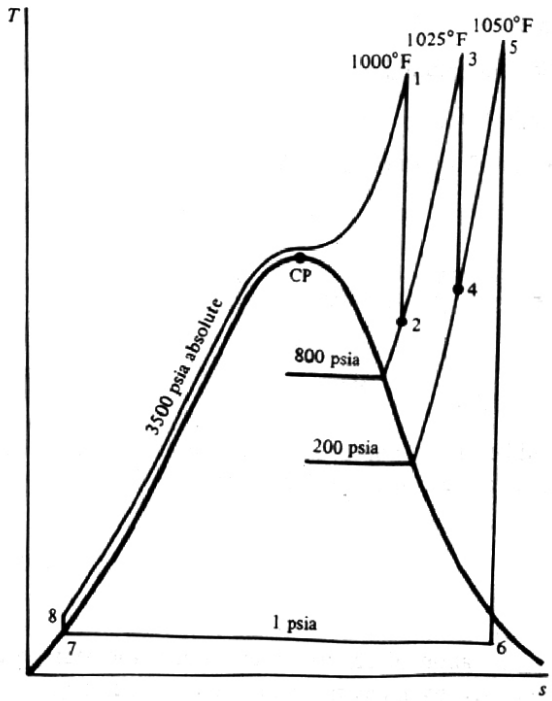

Figure 2.10: T-s diagram of an ideal supercritical, double reheat 241bar/537/551/565°C [8]

Advanced supercritical technology AD700

AD700 represents a joint European research and development project called *"The advanced 700°C pulverized fuel power plant"* [18]. This technology would enable an advanced ultra-supercritical pulverized coal fired power plant operating at efficiencies higher than 50%.

Technology level	Efficiency % HHV	Fuel Costs €/MWh	Investment Cost €/kW	Capital Cost €/MWh	Cost of Electricity €/MWh
State of art 2000	44	16,36	1000	12,01	31,37
AD700 Demo	52	13,84	1100	13,21	30,05
AD700 commercial	52	13,84	900	10,80	27,64

Table 1: Economic performance of AD700 technology [18].

The targets are to reach steam parameters close to 700°C and in the range of 350 to 375 bar. Moreover, a flexible operation to have competitive position in the future power pools (see table 1). These steam conditions can be achieved by modification of design principles and the use of super-alloys for all high temperature parts of HP und IP turbines [31].

It is expected that a lot of aged coal-fired capacity will have to be replaced in the period 2010-30 [18]. Since the first commercial projects may be in service in 2014, AD700 technology is in phase to this period and will play a major role in emission reductions.

2.2. Design and Performance of Steam Power Plants

Through this section, we will analyze the main components of steam power plants, giving special attention to those implemented in the Reference Power Plant North Rhine Westphalia, the followed design in the simulations within this master thesis.

2.2.1. Steam Generator

A steam generator is a complex combination of economizer, boiler, superheaters, reheater and air preheater. In addition, burners, auxiliary components and flue gas emission control equipment. Modern steam generators in power plants are essentially of two basic kinds: subcritical steam drum type and the supercritical once through type.

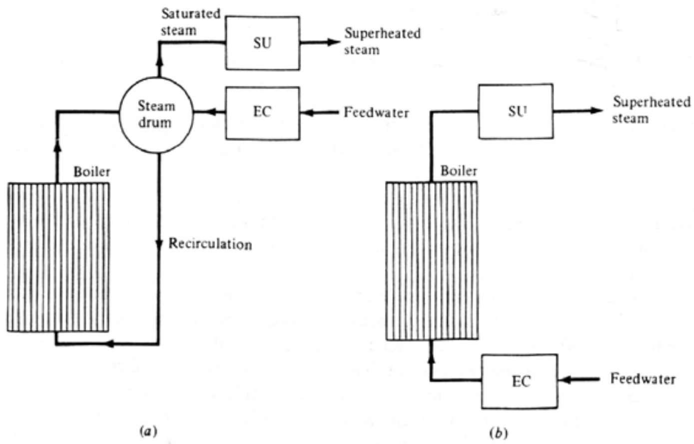

Figure 2.11: Schematic flow diagrams of (a) drum type and (b) once-through steam generators. SU=superheater, EC=economizer [8]

Once-through steam generator is also called forced-circulation or Benson. This steam generator is suited to large sizes and pressures in the high subcritical or supercritical range. In contrast to the drum type represented in figure 2.11a, the feed water goes trough economizer, furnace walls, and superheater sections changing gradually its density and temperature. In supercritical pressure operation, latent heat of vaporization is zero and liquid and vapor are one phase. No drum is required, since no separation is possible or necessary.

The boiler walls: Boiler walls are currently designed as a membrane consisting of tubes welded to membranes that act as fins and a continuous and rigid construction for the furnace. Heat is transferred from the combustion gas to water walls primarily by radiation and some percentage near the walls by convection.

Superheaters and reheater: These components of the steam generator are located after the boiler walls. Heat transfer is primarily by radiation in the ones located in view of the combustion flames, and convection superheaters are placed behind them.

Economizer: As already mentioned, the economizer raises temperature of feedwater to the saturation temperature for the boiling pressure. Economizers are usually located between the last superheater-reheater and the air preheater. To avoid corrosion, economizers operate always above the dew point of the combustion gases.

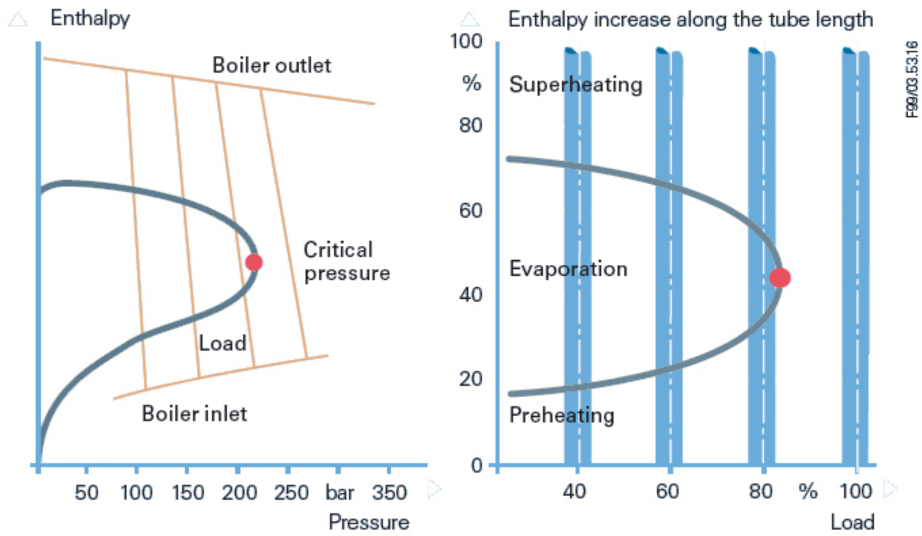

Figure 2.12: (a) Automatic variation of the preheat, evaporation and superheat sections with pressure, (b) relative sizes for each section in sliding-pressure operation [13]

Air preheater: Air preheaters receive energy from the flue gases at temperatures between 300°C to 400°C. Flue gases can be cooled to only 115°C to 175°C to avoid gas condensation and corrosion. Air heaters are not only positive for the overall plant efficiency but necessary for the operation of pulverized-coal furnaces.

Constant and Sliding pressure operation mode

Partload operation in the RPP NRW is controlled by *Sliding Pressure Operation* mode. Constant pressure implies stable pressure of the main steam line over the steam generator. Meanwhile, turbines require less pressure as load and flow rate are reduced. A steam generator working in constant pressure controls the turbine pressure via throttling with significant efficiency losses in part load operation. In sliding pressure operation, pressure at the steam line is adjusted to the required for the turbine operation at each partload.

Sliding pressure operation in supercritical power plants means that at some load, usually around 70%, the steam generator operates at subcritical pressures and therefore the furnace must be designed to accommodate both single and two-phase fluid flow. Under once-through design, flow rate through the furnace is directly proportional to the load. The main advantage of this operation mode is the higher efficiency achieved at part loads, due to a higher HP turbine internal efficiency, less boiler feedwater pump power consumption and higher reheat steam temperatures at partial load. State-of-art Benson steam generators implement variable evaporation end point. This feature allows, as already mentioned, constant temperature parameters of the life steam and reheating steam. In subcritical conditions, once-through generators offer the possibility to the evaporation and superheating surfaces to automatically adjust to the operating pressure (see figure 2.12). This way steam temperatures remain constant for partload operation (from 35-40% to 100% load) [13].

2.2.2. Steam Turbines

The design of the turboset for a supercritical power plant depends on the number of reheats selected, life steam conditions and condenser pressure. Typical design consists of three separate turbine modules (see figure 2.13): high pressure (HP) turbine, intermediate pressure (IP) and up to three

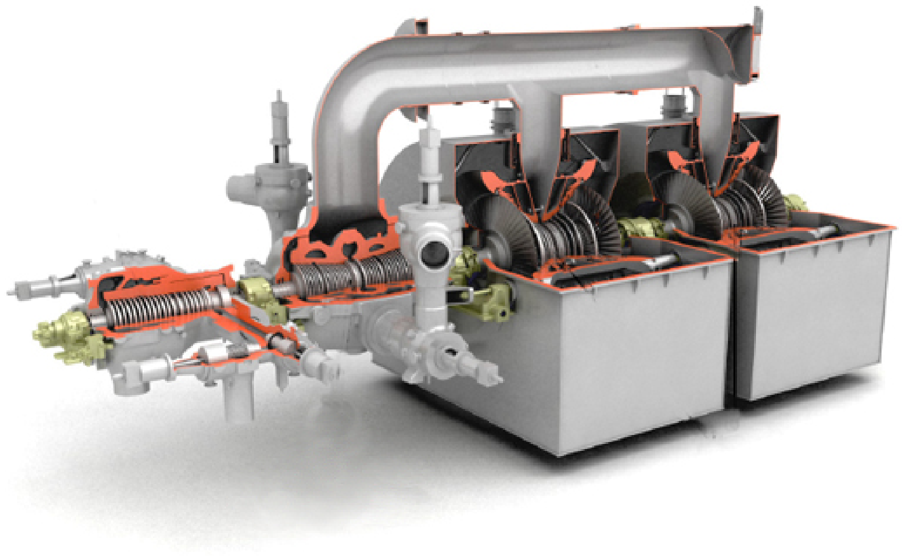

Figure 2.13: RPP NRW Siemens turboset with HP turbine, IP turbine and double LP turbine [31]

low pressure (LP) turbines. State-of-art materials enable steam parameters up to 300bar / 600°C for the HP turbine 620°C for the IP turbine. Further increase to 350bar / 650°C life steam requires design features as active cooling of certain components.

2.2.3. Condensate Feedwater System

Main Condensate feedwater system components are condenser and feedwater heaters. However, other items are crucial for the smooth operation of the power plant such as boiler water makeup and treatment. Section 2.1.2 details theoretical aspects of feedwater heaters. Within this section we will only mention one specific type of heater implemented in the Reference Power Plant North Rhine Westpalia, to better understanding for the future simulation.

Condenser receives steam from the LP turbine and condenses it, closing the water/steam cycle. But a second and even more useful function takes place in the condenser when the circulating cooling water temperature is low enough. Then, since temperature and pressures are linked in the saturation line, low condensation temperatures create a low pressure (vacuum) for the turbine exhaust too. As known enthalpy drop, and as a consequence the turbine work, per unit pressure drop is substantially higher at low pressures than high pressures. Therefore, a small decrease of condenser pressure supposes a significant increase of the plant turbine work and so the overall thermal efficiency increases substantially. For this reason it is important to use cooling medium at the lowest available temperatures.

Duplex Heaters are used in state-of-art power plants as the first two LP preheaters, normally inserted into the condenser neck. Shown in the figure 2.14, a duplex heater consists of two heat exchanger modules in a common shell. The two heater spaces are defined through a partition wall (double-wall to provide insulation in the shell). Both modules can be designed with condensing section, or condensing and subcooling sections. The feedwater flows through the U-tubes of the first heat exchanger module while the extraction steam with the pressure P_1 condenses on the outer surface of the tubes. After the first module, feedwater flows through the second heat exchanger module and is further heated by the steam extraction at P_2 to finally leave the duplex heater. The condensate is discharged at the bottom. If subcooling section is included in the design, a flooded

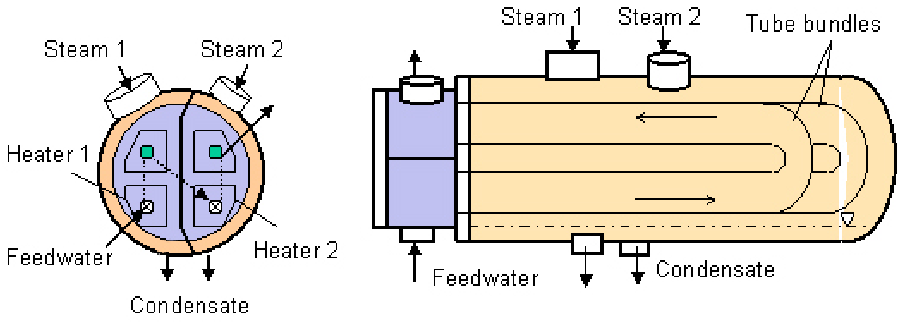

Figure 2.14: Duplex heater with condensing zone operating as the two first low pressure feedwater heaters. Source: Thermal PowerTec Ltd

sectional bundle is chosen. The condensate flows via a siphon into the condenser.

2.3. Steam Power Plant Development

This section is devoted to the analysis of efficiency upgrades as a way to reduce CO_2 emissions of coal-fired power plants in particular. There are various ways to reduce emissions from coal-fired power plants; by efficiency upgrading, by biomass cofiring and employing carbon capture and storage (CCS). But, prior to the widespread application of CCS, the most cost effective way of reducing emissions from coal-fired power plants is to achieve the highest efficiency in new built and existing power plants [18].

Efficiency measures Improvements in CO_2 emissions from pulverized coal power plants are possible by: the use of coal upgrading, improvements in generation efficiency by organization and maintenance measures, improved efficiency by more retrofits and upgrades as changing the plant from subcritical to supercritical and a percentage of coal substitution with biomass [18].

Figure 2.15 ilustrates the cumulative CO_2 emission reduction potential in the European Union from efficiency improvements at existing power plants of all ages. According to the IEA, the average efficiency of coal-fired generation in the OECD was 36% in 2002, compared with 30% in developing countries [18].

The quality of coal used in a boiler has an impact on its overall behavior, on its thermal efficiency and so on the amount of CO_2 produced. Coal upgrading has a number of positive effects. Coal washing reduce mineral matter and sulphur content. Upgrading increases the heating value of coal by reducing its moisture, and a number of secondary effects as reducing the ash content and the load of flue gas static philters and desulphurization unit, and minimizing the presence of abrasive and corrosive materials that increase maintenance.

Efficiency of power plants can also be improved by various housekeeping measures, turbine reblading, improved monitoring and others. Upgrading a subcritical plant to super or ultra-supercritical steam conditions lead to substantial improvements. Many existing subcritical power plants are suitable for advanced supercritical boiler and turbine retrofit enabling this upgrade (see figure 2.16).

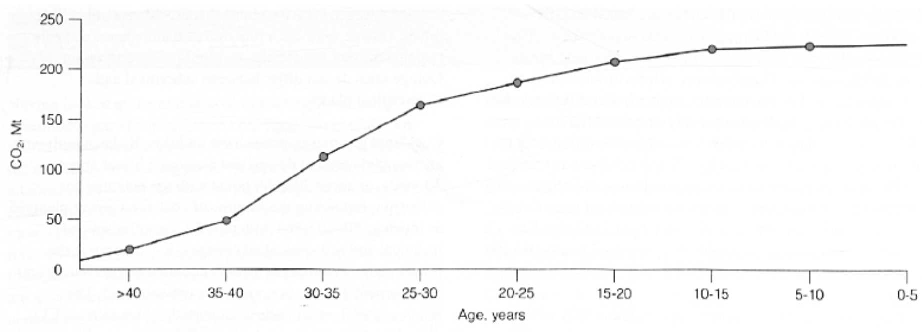

Figure 2.15: Cumulative CO_2 emission reduction potential in the EU from efficiency improvements at existing power plants [18]

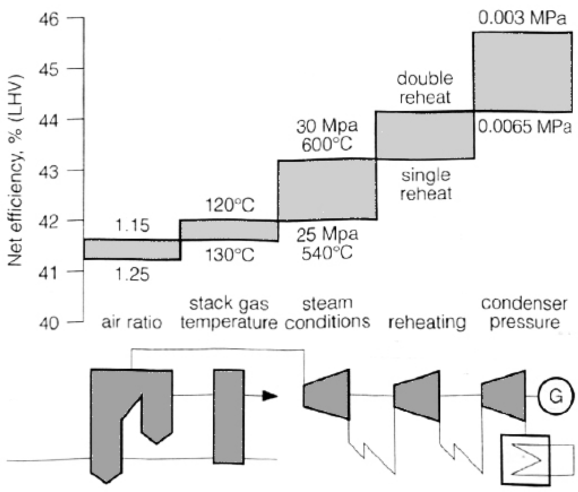

Figure 2.16: Effects of various measures for improving the efficiency of PC-fired power plant [18]

Carbon capture and storage Finally, the path to reach almost zero-emissions will be the installation of carbon capture systems. But it is essentially for power plants with carbon capture to run as effective as possible prior to the addition of CCS as this has a significant cost and efficiency penalty.

3. Carbon Capture and Storage Technology

This chapter will offer a general outlook of the CCS technology. The structure follows the logic path of CO_2 from its source to the final storage site. These are: capture, compression, transport and storage.

3.1. Overview of the CO_2 Capture and Storage and its Development

Carbon capture and storage is a technique for trapping carbon dioxide as is emitted from large point sources, compressing and transporting it to a suitable storage site, where it is stored away from the atmosphere for indefinite time.

History of CO_2 separation from a gas stream starts on the first half of the 20^{th} century [16]. Suitable techniques were developed based on scrubbing a gas stream with chemical solvents. CO_2 capture has been widely applied since then in different industries as food and beverage industry, enhanced oil recovery, hydrogen production or specific chemical processes. But it is only since the 1980's when carbon capture was proposed as one of the solutions for the climate change. Hom and Steinberg (1982) and Hendriks et al. (1989) were among the first to discuss this new application [16]. CO_2 transport benefits from an already mature technology involving transport of gases by pipeline, ships and road tanker. CO_2 storage involves similar technology that is employed by the oil and gas industry for the exploration and production of hydrocarbons [9].

The concept of CO_2 capture and storage is therefore based on a combination of known technologies applied to a new purpose, and to make it viable, a strong effort has to be done in research and development within all fields involved. Other key factors such as cost, environmental concerns, regulation, and public acceptability seriously affect the potential of this technology.

3.2. Baseline Efficiencies and Emissions Reduction

By improving the efficiency of a power plant (see section 2.3), both fuel consumption and, as a result, CO_2 emissions, are reduced. In contrast, the process of capture, transport and storage CO_2 requires additional expenditure of energy (see figure 3.1), and thus causes a penalty in efficiency and an increase in the plant CO_2 generation.

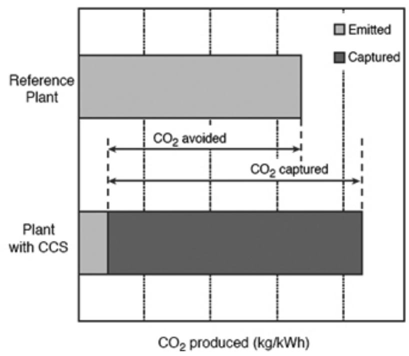

Figure 3.1: Increased CO2 production resulting from loss in overall efficiency of power plants due to the additional energy required for CCS [16]

The specific CO_2 emissions reduction of a power plant with carbon capture is the reduction in the emitted CO_2 at equal level of power generation than the reference power plant (the same power plant without CO_2 capture). ϵ_{CO_2} can be calculated as [14]:

$$\epsilon_{CO_2} = 1 - \frac{\left(\frac{\dot{m}_{CO_2,emitted}}{P_{el}}\right)_{ccs}}{\left(\frac{\dot{m}_{CO_2,emitted}}{P_{el}}\right)_{ref}} \tag{3.1}$$

Since CO_2 involves efficiency penalties the CO_2 emission reduction described in the last paragraph differs from the CO_2 capture ratio. Equation (3.1) is equivalent to [14]:

$$\epsilon_{CO_2} = 1 - \frac{\eta_{ref}}{\eta_{ref} - \Delta\eta} \cdot \left(1 - r_{CO_2}\right) \tag{3.2}$$

Where r_{CO_2} is the CO_2 separation ratio and $\Delta\eta$ is the difference between efficiency without capture (η_{ref}) and with capture (η_{ccs}). This equation shows how the emissions reduction is affected less by $\Delta\eta$ when the power plant has high values of η_{ref}. For this reason is essential to achieve the highest possible level of baseline efficiency, prior to consider CO_2 capture in new and existing power plants.

3.3. Capture Technology

There are three main capture techniques that are currently in advanced stages of development and could make CO_2 capture commercially viable on a large scale. These techniques are *Oxy-fuel*, *Pre-combustion* and *Post-combustion*. Other techniques in less advanced state of development like CO_2 capture with fuel cells or the direct fixation of CO_2 in solid carbonates will not be considered in this study, but extensive literature can be found in sources as [16, 14].

3.3.1. Oxyfuel Combustion

In oxyfuel combustion, nearly pure oxygen is used for combustion instead of air. A mixed flow of oxygen and recycled flue gas enters the boiler with fuel. Combustion produces a gas stream mainly composed by CO_2 and water vapour.

Combustion of a fuel with pure oxygen has a combustion temperature of about 3500°C which is far too high for typical power plant materials. To reduce flame temperature, typically 70 to 80% of the flue gas is recycled. The remaining flue gas follows a sequence of steps (see figure 3.2) where water and sulphur are removed. After that, CO_2 stream is compressed, dried and further purified before transportation for permanent storage [16].

In the feasibility study, *Large Scale CO_2 Capture - Applying the Concept of O_2/CO_2 Combustion to Commercial Process Data*, researchers of the Chalmers University realized a combined comprehensive study of the flue gas treatment together with integration possibilities of the O_2/CO_2 process retrofitted to a commercial power plant [4]. To minimize the need of redesign burners, convection surfaces, etc. an air-like mixture of 20% vol. oxygen and 80% vol. recycled flue gas was chosen.

[4] 2x865MWel lignite-fired, Lippendorf, property of Vattenfall

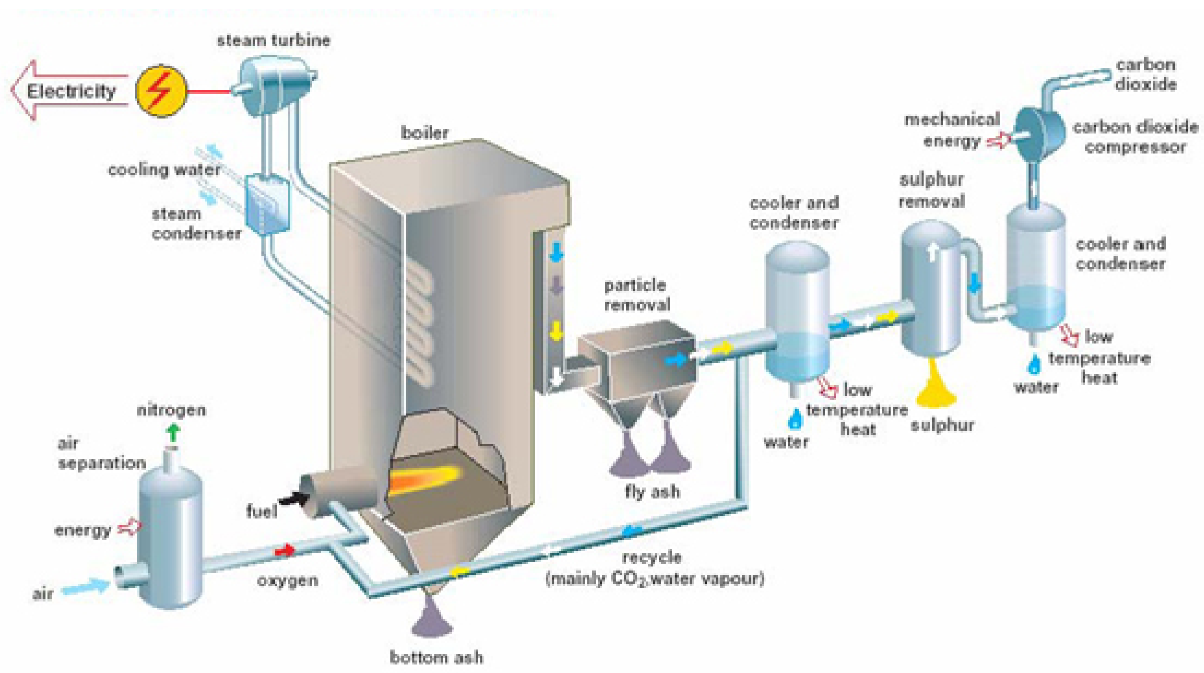

Figure 3.2: Schematic oxyfuel O_2/CO_2 combustion. Source: Vattenfall

The results of this study show that with all integration possibilities considered, net electrical efficiency decreases approximately from 42,6% to 34% and cooling water requirements increase by 50%. Figure 3.3 shows a Sankey diagram of the simulated oxyfuel plant [22].

Some companies and institutions point substantial drawbacks of this technique: the high energy-intensive process of air separation, the importance of boiler modifications required to enable retrofitting or the vast increase in cooling requirements. Additional components are required for retrofitting: among them, the Air Separation Unit (ASU), oxygen and flue gas recirculation ducts, recirculation fan, corrosion protection for cold flue gas recirculation, modifications on the mills and an increase of cooling water [30].

Other oxyfuel combustion configurations are being analyzed, and new possible configurations appear according to how the heat of combustion is supplied and whether the flue gas is used as a working fluid. Further information is available in [16, 14].

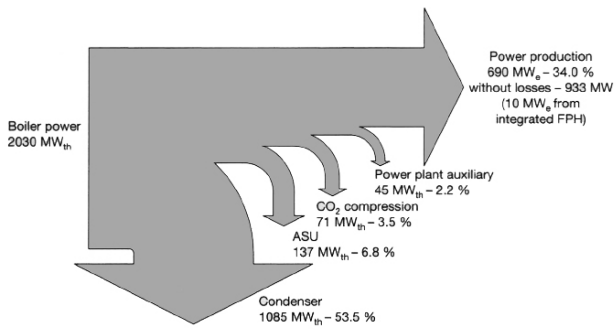

Figure 3.3: Sankey diagram for O_2/CO_2 combustion [22]

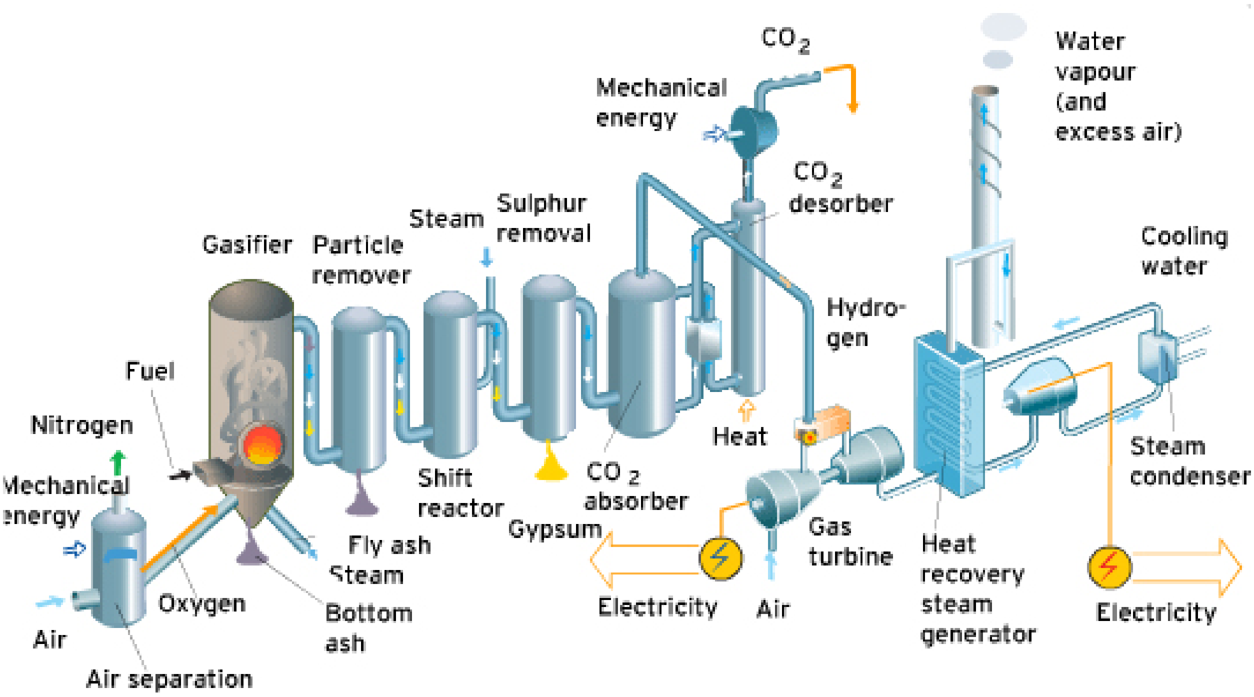

Figure 3.4: Schematic pre-combustion system. Source: Vattenfall

According to GÖTTLICHER oxyfuel would be the preferred option in the long term. The main reasons are the lower expected consumptions and costs of the ASU with membrane technology for oxygen production (a technology already outlined) and the high potential integration of the ASU with the rest of the power plant [14].

3.3.2. Pre-combustion

Pre-combustion is used in Integrated Gas Combined Cycle (IGCC) power plants, a new generation of high efficiency coal-fired power plants. The principle of this technology is to separate the CO_2 before the fuel is burned. The first step of this process is to separate air into nitrogen and oxygen in the ASU. After, in the *Gasifier* coal is gasified at high temperatures to produce a gas stream consisting mainly of CO_2 and carbon monoxide CO. This synthetic mixture is called *Syngas*. (See figure 3.4).

When the *Syngas* is mixed with steam into the Shift Reactor, the CO from the incomplete combustion reacts with steam and produces Hydrogen, resulting in a mixture of CO_2 and H_2. The main chemical reactions are *partial oxidation* (3.3) and *water gas shift reaction* (3.4):

$$C_xH_y + \frac{x}{2}\mathrm{O}_2 \leftrightarrow x\mathrm{CO} + \frac{y}{2}\mathrm{H}_2 \tag{3.3}$$

$$\mathrm{CO} + \mathrm{H_2O} \leftrightarrow \mathrm{H}_2 + \mathrm{CO}_2 \tag{3.4}$$

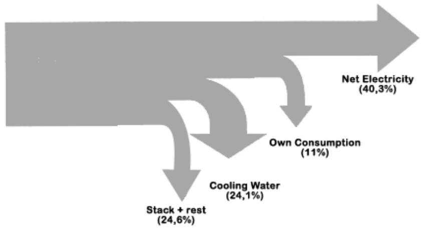

Figure 3.5: Sankey diagram of a state-of-art IGCC power plant with CO_2 capture [12]

The CO_2 is then washed out of this gas mixture and pressurized for transport to a storage facility. The remaining hydrogen can be used as fuel or at the moment to generate electricity in a combined-cycle gas turbine (CCGT), which operates at a high level of thermal efficiency. With new gas turbine technology and without capture, high efficiencies can be achieved with IGCC. Net efficiency reaches 50% without CO_2 capture and with 90% capture ratio drops to values near 40%. Figure 3.5 shows the Sankey diagram of the state-of-art IGCC with CO_2 capture.

Mayor benefits of pre-combustion technology are: high net efficiencies, extremely low levels[5] of environmental pollution, Capability of co-firing "dirty fuels"[6] and easier separation of CO_2 from the hydrogen than from conventional flue gas. On the other hand, the complex equipment numerous processes taking place, increase substantially the initial investment. In addition, hydrogen gas turbine still requires improvements and validation before large scale IGCC becomes available [12].

3.3.3. Post-combustion Capture

Flue gases of a conventional coal-fired power plant content approximately 15% of CO_2 (by volume). To capture it, the Post-combustion Technology adds a new step after the conventional flue-gas purification equipment. The CO_2 capture takes place when flue gas column is exposed in the *absorber* to a solvent that absorbs CO_2. The CO_2-saturated solvent (loaded or rich solvent) is introduced into a second column, called *desorber* or *stripper*, and heated with steam until the CO_2 is separated and washed out. Thus, regenerated solvent returns again to the *absorber*, resulting a closed scrubbing cycle with minimum solvent losses (see figure 3.6). Up to 99.5% of the CO_2 produced can be extracted from the flue gases.

Gas chemical separation process has been used for decades. Today, chemical and other industries already use CO_2 scrubbing processes for different applications, of course, with inferior volumes than the required for the actual power plants and also for higher partial pressures.

As in all capture technologies, CO_2 removal induces an efficiency penalty to the power plant. Despite the CO_2 absorption reaction has low enthalpy, the washing process of loaded solvent consumes high amounts of steam that has to be removed from the steam cycle or generated with an auxiliary boiler. The impact of the process is a loss between 9 to 15% of net efficiency. That is why one of the key research and development tasks is to minimize this steam requirement, by improving solvents and integration to reduce this efficiency penalty.

[5] In Particular, NOx emissions kept below permissible levels without the requirement of further flue-gas treatment equipment, Thanks to the previous nitrogen removal in the ASU.
[6] Low-grade coals, refinery residues, wastes or biomass.

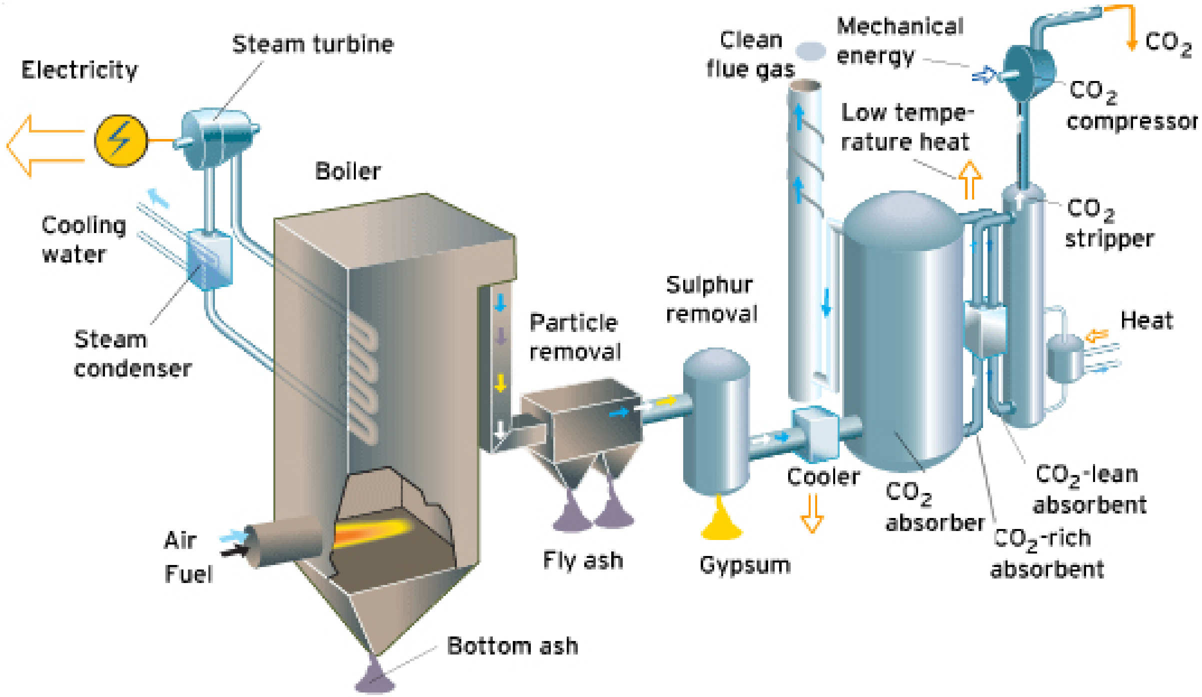

Figure 3.6: Standard process configuration for CO_2 absorption and desorption from flue gases. Source: Vattenfall

As a specific part of this thesis, Post-combustion capture will be widely analyzed in chapter 4.

3.3.4. Summary

All three capture alternatives have big potential. However, there is a difference in validation status within these technologies. Pre-combustion is more advanced than Post-combustion and Oxyfuel with regard to the validation and scale-up expectations. With regard to the retrofit on existing power plants, pre-combustion and oxyfuel require a large degree of interaction and modifications. Post-combustion CO_2 capture will therefore continue to be the preferred CO_2 capture path for existing CO_2 sources even if pre-combustion or oxyfuel CO_2 capture become the preferred choice for new power plants and factories [34].

Technology block	Potential eff increase	CCS Tech impact
Air separation unit (ASU)	0,5 - 2%	IGCC, Oxyfuel
Gas turbine	0,5 - 2%	IGCC
Steam parameters	2 - 4%	IGCC, Oxy-Fuel, Post
Fuel conditioning	1 - 4%	IGCC, Oxy-Fuel, Post
Plant integration	1 - 4%	IGCC, Oxy-Fuel, Post

Table 2: Potential efficiency increase compared to the actual state-of-art and the impact over the different capture technologies [34]

Overall integration is a major challenge for all technologies. Each one involves energy intensive processes - ASU, CO_2 separation, or solvent washing - that have to be improved and highly integrated to minimize efficiency drop. In a parallel approach, baseline efficiency improvement through steam parameters and other measures (see section 2.3) should be translated in less consumption and ease integration for Post-combustion and oxyfuel [34]. During the following years a large number of demo projects will have to be into operation to validate technology blocks and integration, and enhance plant performances for the future scale-up [34].

3.4. Compression

For transport and storage, CO_2 compression is required to reduce CO_2 volume. In its dense phase (supercritical), CO_2 occupies around 0,2% of volume compared to ambient conditions, and minimizes friction losses. Optimal transportation condition is therefore supercritical [16]. However, the CO_2 final pressure required for transportation depends on the characteristics of the final storage or reinjection site. CO_2 is generally compressed over supercritical pressure up to 100 to 150 bars [34].

Supercritical state occurs at higher temperatures than 31,1°C if the pressure is greater than 73,9 bar. At this point CO_2 behaves like a gas approaching or even exceeding the density of liquid water. The phase changes from supercritical condition to liquid or to gas do not require or release heat. This is a useful property for the design of CO_2 compression facilities.

3.4.1. Compression Strategies

The *Carbon Capture Journal special edition* of October 2009 analyzes the state-of-the-art and innovative technologies for the CO_2 compression market. Here, various compression strategies for Post-combustion CO_2 capture were compared to better understanding of their potentials and limitations [32, 4, 15, 3].

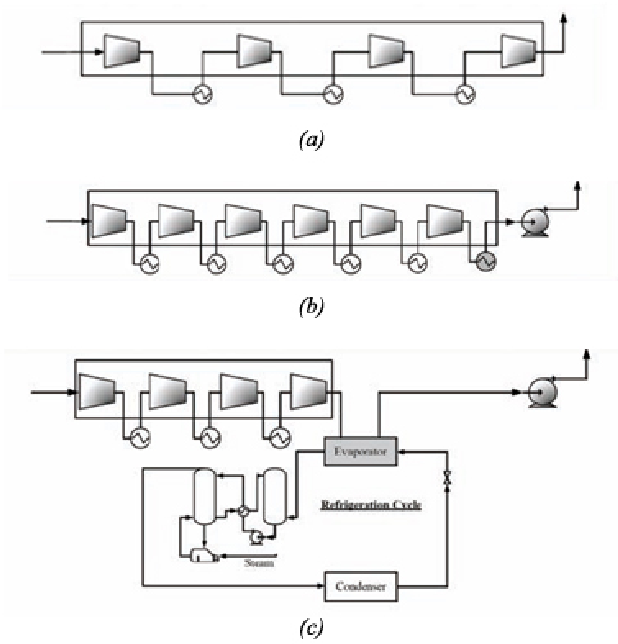

Figure 3.7: Different compression strategies for CO_2 [4]

- **Simple compression**: Four compression stages with intermediate cooling (20°C ambient water). Pressure increase from 1,5 to 220 bar. This is the simplest case and the reference point for this comparison (see figure 3.7a).

- **Compression in gas phase with recooling and supercritical compression in the high density area**: CO_2 stream is compressed over the supercritical pressure in six stages with intercooling (20°C ambient water) with subsequent cooling at a compressor outlet pressure of 80bar. The dense fluid can be pumped to the final pressure (see figure 3.7b).

  This strategy can be improved depending always on the minimum pressure required for liquefaction with the cooling water at ambient conditions. For 20°C minimum pressure is 60 bar. At this point, third option follows this approach to compress only to 60 bars.

- **Refrigerated Compression/Pumping**: Gas compression is an energy-intensive process compared to pumping fluids. Since the limiting factor to reduce the compression stage is the cooling fluid temperature, a new approach can be analyzed when a refrigeration cycle is used (see 3.7c).

  As it is known, temperatures and pressures are coupled in the saturation region, meaning that liquefying CO_2 from low pressures will require very low temperatures. According to Bertolo [4] the selected liquefaction pressure for the study was 17 bar, corresponding to a liquefaction temperature of -30°C. This option would include an absorption refrigeration cycle. These cycles can be economic in cases where heat energy is available at temperatures between 100°C and 200°C. Such could be the case for combined cycles using the steam in the bottoming cycle. However, limitations due to the physical properties of CO_2 and requirements for the compression process make this option not realistic.

Figure 3.8 shows P-h diagrams for the different CO_2 compression strategies. In conclusion, compression power savings of almost 20% can be achieved if the CO_2 is liquefied and then pumped. This savings can be maximized if liquefaction takes placed at the minimum pressure allowed by the cooling fluid temperature. A refrigeration cycle would save up to 40% of the compression stage. However, the additional compression power for this refrigeration loop will contrast all savings and add overall system complexity [4].

3.4.2. State of the Art CO_2 Compressors

Historically, in CO_2 compression for Enhanced Oil Recovery (EOR), the approach has been the use of high-speed reciprocating compressors. But this technology shows several limits; limited volume flows exceeded by most CCS schemes today, problems with high velocities caused by the density of CO_2 or intensive maintenance. For this reason, centrifugal type compressors are now state of the art [32]. Centrifugal compressors offer better efficiencies, simple lubrication, higher capacities and other benefits. The two main centrifugal technologies are: *Single shaft Compressors* (in-line between bearings) and *Multi-shaft integral gear compressors*.

According to several articles within the *Carbon Capture Journal* of october 2009 [32, 15]. Multi-shaft integral gear compressors are the preferred option for post-combustion technology. Gear type

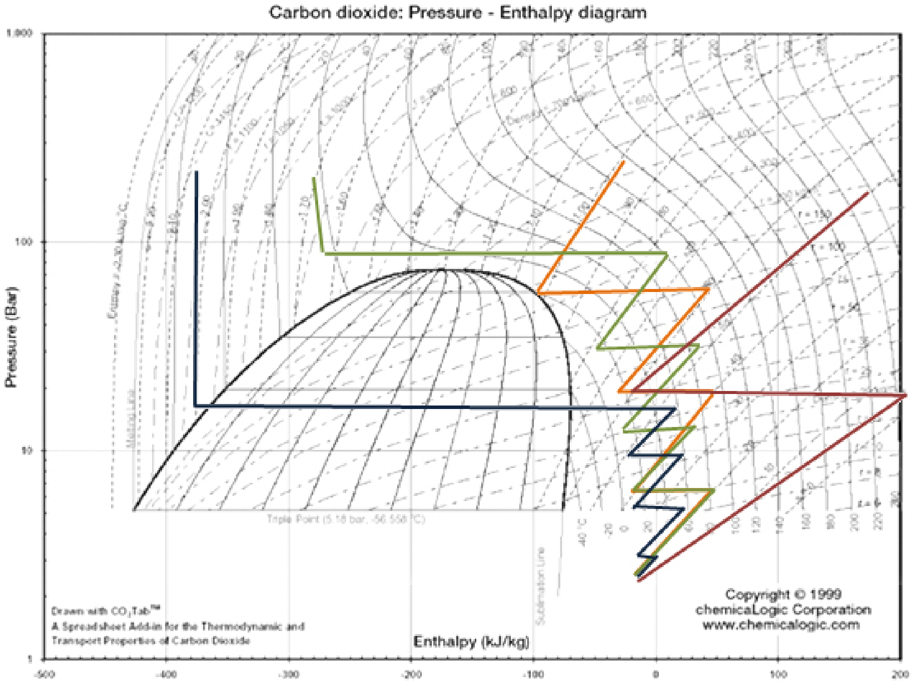

Figure 3.8: P-h diagram for different compression strategies. Orange line: four stages compression with intercooling. Green line: compression in gas phase with recooling and supercritical compression in the high density area. Blue line: compression, subcritical liquefaction/-subcooling and pumping. Red line: compression in gas phase with compression in supercritical low density area (Shockwave compression) [4, 3]

compressors display better efficiency and lower power usage when compared to inline centrifugal, reciprocating or to the new shockwave technology[7].

3.4.3. Compression Development. New Shockwave Technology

Standard turbomachinery design practice is to limit the inlet *Mach* number to less than 0,90 to avoid shock waves and the consequent losses. This limitation results in a limited pressure ratio between *1,7:1* to *2:1* for each stage. Ramgen® concept applies a new approach using Mach numbers bigger than 1 (see figure 3.9), enabling *10+:1* pressure ratios per stage [3].

This compression system allows the CO_2 compression in only two stages. Figure 3.8 shows in red line how a compression in the supercritical low density region results in high temperatures. Thus, the two intercoolers designed offer high quality heat at 255°C-265°C[8] available for heat integration. According to Baldwin [3] these stage coolers could be even the solvent stripper boiler itself. In contrast, state-of-art centrifugal compressors have generally a heat discharge temperature of 90°C-100°C, insufficient heat quality for integration, furthermore, this waste heat increases cooling requirements, process complexity and installation investment.

Ramgen asserts that this novel technology requires 50-60% less investment than integrally geared centrifugal compressors, and shows important advantages as operational and high potential for heat integration. Capacity planned for the two stages compressor would be able to support the

[7] Siemens conducted a study where shockwave compressors reach 66% isothermal efficiency while integrally geared compressors have 80% [32]

[8] Approximately 630 kJ/kg CO_2 [3].

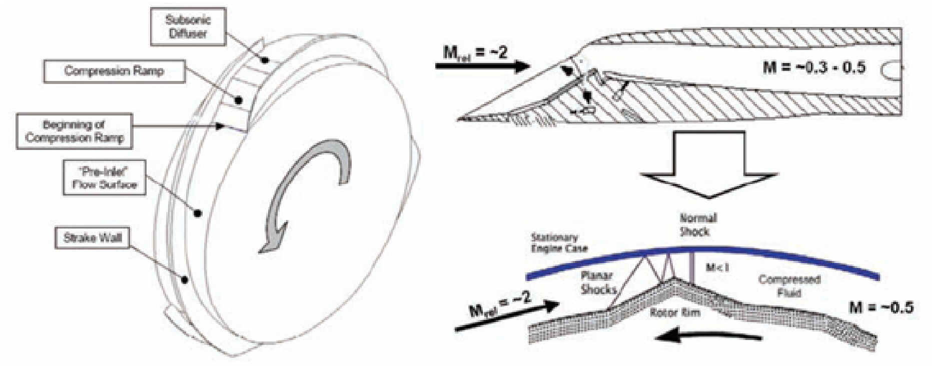

Figure 3.9: (a)Supersonic compression stage rotor and (b) Shock structure and comparison to flight inlet [3]

full capacity 800MW of a commercial power plant. Commercialization plan shows Ramgen Power Systems will be able by year end 2011 to make firm commitments for projects with commercial operating dates scheduled for the 2014/2015 timeframe [3].

3.5. CO_2 Transport

CO_2 pipelines over distances even greater than 500 km have been in operation for over 30 years. There are already about 5,000 kilometers of underground pipelines in North America used to transport CO_2 from natural reservoirs to oil fields. The largest network supplies Permian Basin operators, in Texas and New Mexico, which have been injecting CO_2 for 35 years without any significant safety incident. Shorter pipelines are used in other locations by beverage and chemical manufacturing facilities. As written in the previous section, optimal CO_2 state for transport is supercritical. At this point CO_2 volume and friction losses are minimized. Within pipelines, friction can cause pressure losses from 4 to 15 bar per 100km. However, for larger diameter pipelines losses are limited and booster stations are not required.

Shipping could offer a flexible operation for smaller quantities and long distances. Several existing ships are already certified for CO_2 transport. Risks in transport can be minimized by making certain high standards of construction and operation currently applied to LPG ships also compulsory to carbon dioxide ships [11].

3.6. CO_2 Storage

There are two main options when it comes to CO_2 storage: The first one is geological storage, second option considered is ocean storage.

The basics of ocean storage is to inject captured CO_2 directly into the deep ocean (at depths greater than 1,000 m). The dissolved and dispersed CO_2 would remain stored in "lakes" over the sea bed, because of the density difference between water and the CO_2-water dissolution. Analysis of ocean observations and models both indicate that injected CO_2 will remain isolated from the atmosphere for at least several hundreds of years. However, ocean storage is not an attractive option because of the gap of knowledge and unclear aspects that involves. EU and most countries have rejected this option [16].

3.6.1. Geological Storage Reservoirs

CO_2 geological storage can only take place in locations where the geology ensures that there will not be any leakage. To be sure that the CO_2 is contained in the porous rock layer, a solid, non-porous, layer of rock called *cap rock*, must lie on top of the porous layer, providing a *'cap'* that does not allow CO_2 to permeate to the surface. CO_2 can be stored either onshore or offshore (under the sea bed) at depths of several kilometers. Three geological formations can be used, in order of potential storage capacity: *saline aquifers*, *depleted oil and gas fields* and *unmineable coal seams.*

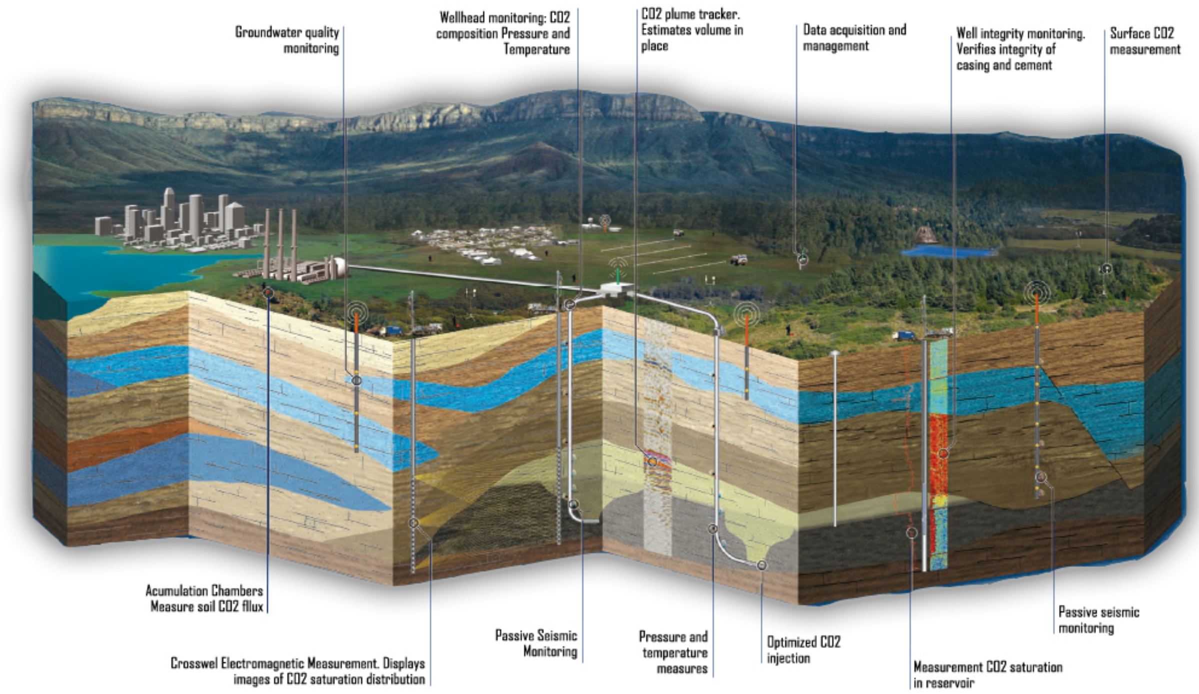

Figure 3.10: CO2 Storage: Monitoring and Verification. Source: Schlumberger

Saline aquifers represent a promising solution for storing CO_2 deep underground. Cap rock above the aquifer ensures that the CO_2 doesn't escape. These aquifers are already used for temporary storage of natural gas [34]. Identifying storage reservoirs is a meticulous task similar to exploring for oil or natural gas. Here, industry's decades-long experience in underground natural gas storage is particularly useful. This geological expertise can be transferred to the task of finding and developing safe and secure CO_2 storage [9].

Monitoring is a critical issue for storage and transport of CO_2 (see figure 3.11). The reasons for monitoring storage sites are operational (for optimize injection process), safety and environmental (predict possible leakages and minimize any impact), and also financial (to enable certified *"avoided emissions rights"* for future trading in the European Union's Emission Trading System). In the near future CO_2 transport and storage will be regulated by governments and monitored by independent agencies to ensure safety and environmental compliance.

Great efforts are being made in research and development to improve monitoring technology for Storage and Transport of CO_2, and significant advances are expected by the time CCS would become commercially viable [11].

3.6.2. Permanent Storage Mechanisms

When the CO_2 is injected, spontaneously fills the rock's spaces displacing saline water. Once there, four natural mechanisms contribute to permanent trapping. Figure 3.11 shows how the security if the storage site increases with the time.

- **Structural trapping**: CO_2 is not as dense as water, and so, it begins to rise upwards. Here is when the *cap rock*, an impermeable barrier of clay or salt, prevents the CO_2 leakage.

- **Residual Trapping**: When the pore spaces in the reservoir are so small, CO_2 can no longer move upwards despite the difference in density.

- **Dissolution Trapping**: A small portion of the CO_2 is dissolved by the existing water in the aquifer. This water dissolution is heavier than the water and move downwards to the bottom of the reservoir. The natural movement upwards and downwards of CO_2 and Water-CO_2 contributes to increase the quantity that can be dissolved. Historic data in the *Sleipner Project* in Norway estimate than 15% of the injected CO_2 is dissolved after 10 years [16].
- **Mineralization**: The dissolved CO_2 in the bottom of the reservoir will form ionic species as the rock dissolves, accompanied by a rise in the *pH.* Finally, some fraction may be converted to stable carbonate minerals. This is a very slow process that takes place in thousands of years.

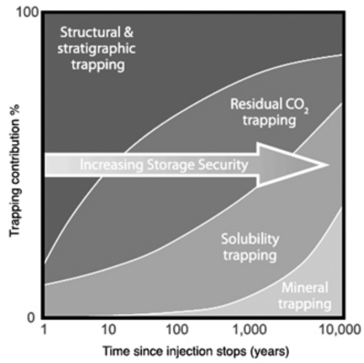

Figure 3.11: Physical process of residual CO_2 trapping and geochemical processes of solubility trapping and mineral trapping become the main mechanisms over the time. Thus, storage security increases with time [16]

3.6.3. Storage Capacity in Europe

Storage reservoirs can be found in sedimentary basins that are widespread throughout Europe. Storage capacity estimations are highly approximate. There is a strong need of update and map precisely the storage capacity in individual countries and through the whole Europe. But, even with uncertainties Europe has high CO_2 storage capacity. Around the North Sea the estimated storage capacity would enable large installations to inject CO_2 for several decades [11].

3.7. Legal and Regulatory Frameworks

Since 2009, EU legislation on geological storage of CO_2 is in place. The New Directive 2009/31/Ec Of The European Parliament And Of The Council Of 23 April 2009 On The Geological Storage Of Carbon Dioxide, provides the necessary regulatory framework and ensures that CO_2 will be safely and permanently stored underground. The EU legislation now needs to be transposed into national laws in member states.

4. Post-combustion Capture Technology

As mentioned before, post-combustion capture is the CO_2 separation from the flue gases. The energy required for this separation depends on the concentration of CO_2 in the flue gas and the gas separation method [14].

Table 3 shows the different CO_2 concentration in the flue gas for conventional power plants. Separation methods show better performance when the initial concentration of the component to separate is high. For this reason, dilute CO_2 concentration in flue gas is the main challenge for post-combustion technology.

Flue gas	CO_2 concentration %vol (dry)	Pressure of gas stream (bar)	CO2 partial pressure (bar)
Natural gas fired boilers	7-10%	1	0,07-0,1
Gas turbines	2-4%	1	0,03-0,04
Oil fired boilers	11-13%	1	0,11-0,13
Coal fired boilers	12-14%	1	0,12-0,14

Table 3: Concentration and partial pressure in flue gases of different combustion systems [24]

The extremely low CO_2 concentrations achieved in gas turbines lead to higher specific energy consumption for CO_2 separation than in coal fired power plants. Flue gas recirculation is presented as a solution to increase CO_2 concentrations in gas cycles [14].

There are several separation methods as chemical absorption, membrane adsorption, physical absorption, distillation, freezing [14]. At present, the leading method is based on chemical absorption or CO_2 scrubbing using solvents (mainly amine based). The main advantages of solvent scrubbing over other methods, even other capture techniques, are the possibility for retrofitting and the fact that it has been commercially proven on small scale [5].

In the following sections we will analyze the standard post-combustion process based on MEA solvent. Other solvents are also summarized for a better outlook.

4.1. The Basic Absorption Process

The basic post-combustion capture presented in figure 4.1, consists of three main sections: flue gas pre-treatment, CO_2 separation section and solvent regeneration. CO_2 compression is usually included as an additional part of the post-combustion capture plant.

4.1.1. Flue Gas Pre-treatment

Flue gas from the stack is at high temperature and contains impurities that degrade the solvent. Before entering the absorption column, flue gas temperature must be reduced to approximately 40°C in order to positively affect the exothermic reaction between CO_2 (weak acid) and the solvent (weak base). High temperatures will slow down the reaction.

Impurity concentration depends on the source of the flue gas. Coal-fired power plants content high amounts of impurities that have to be reduced before entering the capture plant.

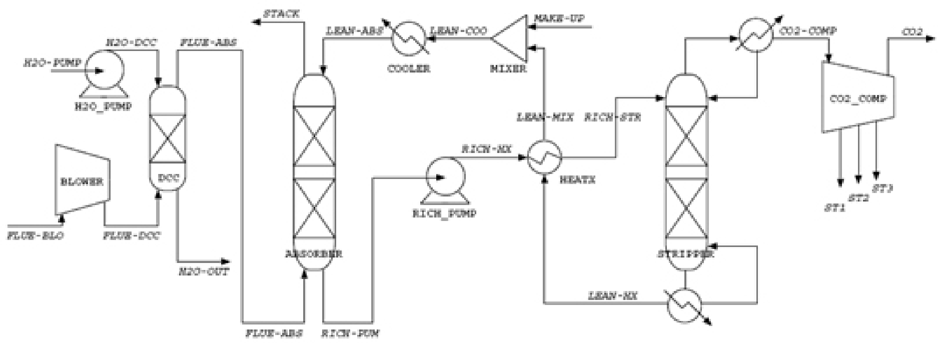

Figure 4.1: Basic process flowsheet for MEA absorption [1]

- **Fly Ash**: Fly ash causes foaming in the columns and plugging, scaling, corrosion, erosion in equipment. This impurity is reduced to adequate levels in the existing electrostatic precipitator of commercial power plants.

- NO_x: NO_x needs to be reduced below 20 ppm.

- $\mathbf{O_2}$: O_2 oxidizes carbon steel and degrades amine based solvents. Some solvents like Fluor Daniel's Ecoamine® use oxygen inhibitors to diminish degradation. Alternative approaches are the use of oxygen-tolerant alloys or removal of all oxygen from the flue gas.

- SO_x: SO_x reacts irreversibly with amine based solvents to form heat-stable salts (HSS) which reduce absorption capacity of the solvent. SO_x has to be removed below 10 ppm to minimize the degradation rate and optimize operational costs of solvent loss and reduce frequency of reclaiming operations[9]. An additional Flue Gas Desulfurization is usually required when retrofitting existing steam cycle power plants with post-combustion.

4.1.2. CO_2 Separation

Once cleaned and cooled down flue gas consists mainly of CO_2, N_2 and water. The blower overcomes the pressure losses in the column and the conditioned flue gas is conducted to the CO_2 absorber column. The flue gas is introduced trough the bottom section of the absorber and moves upwards while the solvent is distributed from the top. The flue gas comes in direct contact with the solvent at the surface of the packing material, where CO_2 is chemically absorbed into the solvent.

Advanced designs for the CO_2 absorption column (Mitsubishi Matsushima Demonstration Plant) include an additional washing section above where the flue gas comes into direct contact with water to have its amine contact washed out and to be cooled down to maintain water balance within the system. Finally the treated flue gas exits from the top section to the stack [27].

[9] A reclaimer unit is installed to eliminate heat-stable salts when certain preset limits have been reached. The reclaimer boils down the solvent and concentrates the HSS for subsequent discharge of the formed residue.

4.1.3. Solvent Regeneration

The CO_2 rich solvent is collected from the bottom of the absorber and pumped to the CO_2 stripper for regeneration. In the crossed heat exchanger the rich solvent can be heated up by the lean solvent. The heated rich solvent is then introduced into the upper section of the CO_2 stripper column, where it comes in contact with stripping steam. Rich solvent is regenerated by thermal treatment at temperatures between 100°C to 130°C and converted back into lean solvent. From the top, a high-purity (dry-basis) CO_2 is produced.

In the crossed heat exchanger, lean solvent is cooled down to approximately 40°C or below[10] before being reintroduced to the CO_2 absorber [1].

All along the process, little amounts of solvent are lost and vented with the cleaned stream and as part of the stripper distillate. The Make-up system balances solvent losses adding the same lost amounts, calculating previously molar flow rates of solvent and water [1].

4.2. Energy Consumption

A large amount of energy is required to operate the state-of-art post-combustion capture plants, leading to substantial overall efficiency drops and gross power output reductions. According to Siemens calculations, the standard process layout for post-combustion capture leads to an efficiency penalty of 10,4% for a reference coal-fired power plant and 9,2% implementing an improved process layout [25]. Other studies mention net efficiency drops between 7,8% and 15% [30].

4.2.1. Thermal Energy Requirements

The heat requirement for solvent regeneration currently represents the main consumption of the capture plant and has a major impact on the overall efficiency of the power plant. This amount of energy can be obtained from an auxiliary boiler or via steam extraction, de-rating the last turbine stages of the power plant. Different studies have proven that overall efficiency penalty is higher when an auxiliary boiler is used [1]. Therefore, the auxiliary boiler approach is no longer considered in this study[11].

The energy required in the reboiler for solvent regeneration is the sum of three factors [10]:

- **Desorption enthalpy**: is the energy required to break the bond between CO_2 and the active component in the solvent. Reducing this energy requirement can be achieved by using amines with a lower binding energy. However, a trade off needs to be made since low desorption enthalpies are usually linked with slow reaction rates, leading to larger absorber columns, higher pressure drops and as a final consequence increases in blower consumptions [10].

- **Solvent heating**: is the energy required for heating the solvent up to the reboiler temperature. Solvents with higher loading capacities work with reduced solvent flows, meaning less solvent to heat up. In addition, reducing the cross heat exchanger pinch point will decrease

[10] Cooling below 40°C, between 20°C - 37°C, has been proved that increase CO_2 absorption due to increase of the rate reaction.

[11] However, an auxiliary boiler would give flexibility to the power plant and could enable an increase in output to the grid if it is economically profitable (i.e. in hours when the electricity prices were higher than the costs of the emission rights).

energy consumptions [10].

- **Stripping steam**: energy required to evaporate the stripping steam, which leaves together with the CO_2 and will be condensed to dry the CO_2 before compression. This water flow returning to the stripper is measured with the *reflux ratio*. Reflux ratio can be reduced with the use of new solvents like *KS1*, developed by Mitsubishi Heavy Industries. Further reductions might be achievable by the use of an integrated heat exchanger in the stripper and finally, with the use on non-aqueous chemical absorbents (i.e. ionic liquids) [10].

Table 4 show the different solvent and process parameters that characterize the state of art.

Absorption process development status	Unit	Standard process	Improved process (state of art)
Desorption enthalpy	$MJ/kmolCO_2$	80	70
Cross HTX pinch point	K	15	10
Solvent flow	$m^3/ton CO_2$	20	10
Reflux ratio	$tonH_2O/tonCO_2$	0,7	0,6
Thermal energy	$GJ/tonCO_2$	4,56	3,31

Table 4: Different solvent and process parameters of conventional process and advanced state of art process [10]

As a real example, the first results of the CASTOR Integrated Process in May 2007, shown an average steam consumption equal to 4,4 GJ/ton CO2 at 92,5% CO_2 recovery [33].

4.2.2. Electric Energy Requirements

Additional significant consumptions should be taken into account, since they suppose up to 35% of the total energy consumption (see figure 4.2) of the capture plant. These Electric consumptions directly reduce the electric power output of the power plant and consequently net efficiency.

- Electric power demand of the additional desulphurization plant (FGD).
- Electric power demand of the additional fan.
- Electric power demand of pumps and aggregates in the CO_2 separation and solvent regeneration sections.
- Electric power demand of the CO_2 compressor.

4.2.3. Efficiency and Impact Over the Power Plant

The loss in power output of the steam power plant caused by the steam extraction can be determined by a detailed study of the integrated capture process and power plant. Such study would also include all waste heat flows transferred to the feedwater for preheating purposes. Thus, steam impact calculation depends strongly on the level of integration, and it has to be calculated in a different way for each process flowsheet. GOETTLICHER [14] offers a much simpler analysis which can be used in general terms, establishing a *power equivalent factor* (PeF) which relates the steam needed for the reboiler to the power output reduction.

Power equivalent factor (PeF) Steam for solvent regeneration is extracted usually from the low pressure section of the turbine set and fed back into the steam cycle as a condensate. The reduced output ΔP_T is calculated from the heat consumption $\dot{Q_{reb}}$ through multiplication with a conversion factor α, called power equivalent factor.

$$\Delta P_T = \alpha \cdot \dot{Q_{reb}} \tag{4.1}$$

$\dot{Q_{reb}}$ is the enthalpy difference ΔH_{ext} between the extracted steam and the condensed warm water after utilization. In a first approximation GOETTLICHER assumes that $\dot{Q_{reb}}$ corresponds to the enthalpy of the extracted steam at temperature T_{ext} and pressure P_{ext}:

$$\dot{Q_{reb}} = \Delta H_{ext} \approx \dot{m_{ext}} h(P_{ext}, T_{ext}) \tag{4.2}$$

therefore, the equivalent factor can be calculated by

$$\alpha = \frac{\Delta P_T}{\dot{Q_{reb}}} = \frac{\Delta P_T}{\dot{m_{ext}} h(P_{ext}, T_{ext})} \tag{4.3}$$

where the loss of turbine power ΔP_T corresponds to

$$\Delta P_T = \dot{m_{ext}} \left[h(P_{ext}, T_{ext}) - h(P_{out,turb}, T_{out,turb}) \right] \tag{4.4}$$

Being $P_{out,turb}$ and $T_{out,turb}$ the steam conditions at the exhaust of the turbine. Hence, equivalent factor is calculated:

$$\alpha = \frac{\Delta P_T}{\dot{Q_{reb}}} = \frac{\Delta P_T}{\dot{m_{ext}} h(P_{ext}, T_{ext})} = \frac{h(P_{ext}, T_{ext}) - h(P_{out,turb}, T_{out,turb})}{h(P_{ext}, T_{ext})} \tag{4.5}$$

This calculation does not take into consideration the enthalpy of the condensate flowing back that could be used to preheat the feedwater, reducing this way the power equivalent factor. Moreover, a more precise calculation of the change in power output due to the reboiler heat requirements would require, as already mentioned, a consideration of the exact process of the retrofitted steam power plant with all preheatings from waste heat of the capture plant. GOETTLICHER includes a more precise calculation for α with preheating assuming that efficiency of the power plant is known. P_{cond} and T_{cond} are the condensate conditions after the reboiler returning to the steam/water cycle.

$$\alpha = \frac{\Delta P_T + \eta_{el} \dot{m_{ext}} \left[h(P_{cond}, T_{cond}) - h(P_{out,turb}, T_{out,turb}) \right]}{\dot{m_{ext}} h(P_{ext}, T_{ext})} \tag{4.6}$$

Table 5 shows different values for the power equivalent factor cited in the literature for different extracted steam temperatures and processes [28].

PeF	T_{reg} (°C)	Source	Process
0,18	120	Bolland and Undrum (2003)	-
0,107	133	Hendriks (1994)	MEA optimized
0,25	-	Feron (2005)	Current technology
0,20	-	Feron (2005)	State-of-art technology
0,15	-	Feron (2005)	next generation solvents
0,219	122	Alie (2004)	MEA basic

Table 5: Different values for the power equivalent factor cited in the literature [28]

Once all the energy consumers in the capture plant are adressed, it is possible to compare the relative energy consumption for each component. To enable such comparison, thermal energy requirement of the reboiler is conversed through the power equivalent factor PeF to electrical power drop in the steam turbine. Thus, all elements can be compared by their electric energy requirements. Figure 4.2 obtained from the cited literature, shows the relative energy consumption for the different elements in a standard post-combustion capture plant [25, 7].

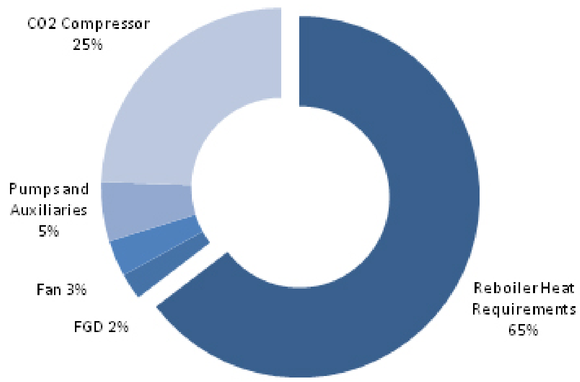

Figure 4.2: Average relative consumptions for the different components of a standard MEA Post-combustion process [25, 7]

Efficiency of the power plant with capture Net efficiency of the retrofitted steam power plant compared to the power plant net efficiency can be calculated as follows [6]:

$$\eta_{CCS} = \eta_{ref} - \frac{Q_{reg} \cdot \alpha \cdot C \cdot r_{\mathrm{CO_2}}}{LHV} - \frac{P_{aux} \cdot C}{LHV} - \frac{P_{comp} \cdot C \cdot r_{\mathrm{CO_2}}}{LHV} \tag{4.7}$$

Where the first term (η_{ref}) is the net efficiency without capture. Second term represents efficiency penalty due to the extraction of steam from the turbine for solvent regeneration. (Q_{reg}) is the specific heat demand for the process and solvent. (α) is the power equivalent factor, (C) gives the ratio between formed CO_2 and consumed fuel and ($r_{\mathrm{CO_2}}$) represents the CO_2 capture rate. As noted above, α depends on the process configuration and grade of heat integration between capture and power plants. Third term gives penalty for consumption due to auxiliaries in the capture plant. (P_{aux}) is the specific consumption of auxiliary components per kg of CO_2. The main consumer here is the exhaust fan gas required to overcome pressure drop in the absorber. Last term addresses the power consumption of the CO_2 compressor.

4.3. Process Operating Conditions

4.3.1. Absorber Column

Absorber column features have a significant impact over the based amine solvents operation parameters: loading capacity, solvent flow, reaction speed and finally, capture plant energy requirements.

Absorber column height: Increasing the height of the absorber, or what is the same the number of trays, results first in an increase of the solvent loading. Less solvent flow is necessary for the same capture rate and therefore, less energy for solvent regeneration is required. In contrast, the pressure drop across the absorber column will increase, leading to an increase of the blower energy consumption. Increase in capital costs need also to be considered. According to Cifre, optimal heights for current absorbers are estimated around 17m [7].

Absorber column pressure: Higher pressures increase the reactivity between MEA and CO_2, increasing loading capacity and thus reducing solvent flow and its regeneration energy. Again, an increase in the absorber column pressure will lead to higher consumptions by the blower, since the increase of the blower consumption is more significant. Absorber columns usually work near atmospheric conditions [1].

4.3.2. Desorber Column

The stripper height does not especially affect the reboiler heat requirement. By contrast, operating pressure, and therefore, operating temperature are critical factors. As the figure shows, increasing operation pressure has a positive impact on the reduction of required energy for solvent regeneration; releasing of the CO_2 is favoured at high pressures. Moreover, higher pressures will lead to a reduction in the total compression ratio and therefore, in the CO_2 compressor energy requirements. However, above temperatures between 120°C-130°C, thermal degradation of MEA increase exponentialy, shown in the figure 4.3 red area. For this reason, pressure at the reboiler is currently set to maintain temperatures close to 120°C, but not higher [23]. It is important to remark that the higher pressure - temperature values in the stripper, the better quality of steam has to be extracted from the power plant, affecting the overall efficiency too.

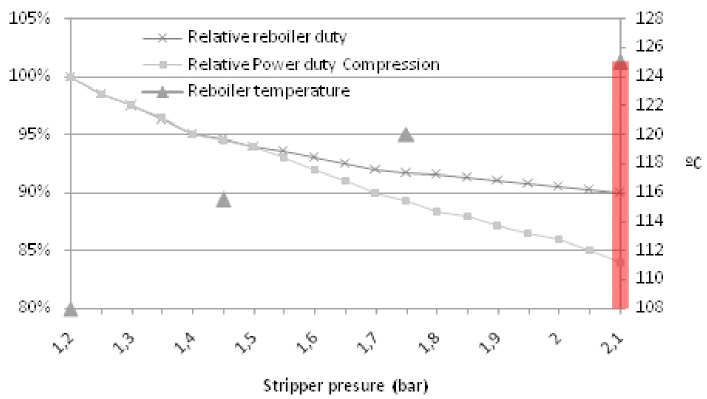

Figure 4.3: Impact of the stripper pressure over the compressor and reboiler energy requirements for MEA solvent [23]

4.3.3. Solvent Flow Rate

Solvent flow rate affects directly to the CO_2 loading of the lean solvent. Low solvent flow requires lean solvent with very low amounts of CO_2 to maintain the capture ratio. This means that more stripping steam has to be generated to intensively wash out the CO_2 from the solvent. In contrast, with high solvent flows decrease the necessity of a "very lean" solvent, but increase energy required for heating up the solvent (see section 4.2.1). The optimal flow rate will have to be calculated in order to minimize energy requirements [23, 7, 1].

4.4. Modifications on the Steam Power Plant

The power plant steam cycle has to provide a significant amount of heat in form of steam to feed the reboiler for solvent regeneration. Besides, as we have noted above, additional electric power consumptions and cooling water supply have to be delivered for the capture plant and the CO_2 compressor. Solvent regeneration (for the conventional amine solvents) requires heating up the dissolution to generate stripping steam up to 120°C - 130°C approximately. But increasing more than 130°C the solvent temperature will lead to unsustainable values of amine degradation (section 4.2.1). For this reason, steam extracted from the power plant has to fulfill certain criteria. Thus, for a conventional pinch point in the reboiler, a minimum steam saturation temperature between 130°C - 140°C and steam pressures between $P_{sat,130C}$ = 2,7 bar $P_{sat,140C}$ = 3,6 bar have to be guaranteed [35].

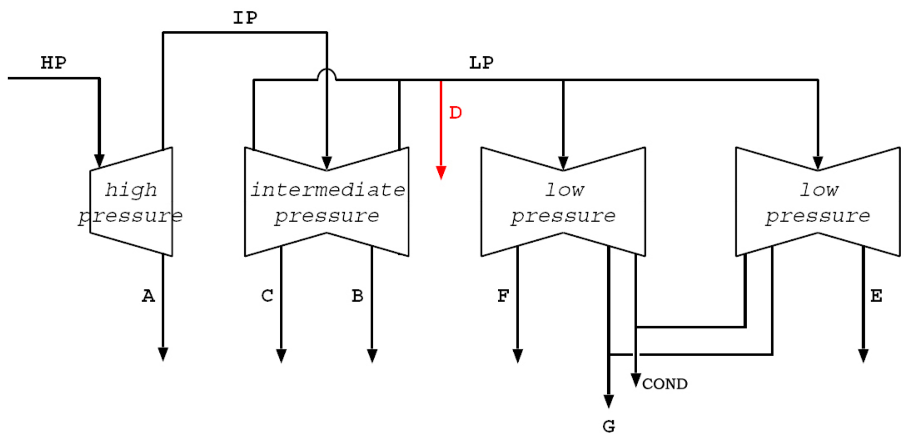

Figure 4.4: Schematic of the steam turbine with the location of all potential steam extractions [1]

Steam can be extracted from the steam pipes which flows to or of the HP, IP and LP turbines as well as from the steam extraction points used to preheat the feed water (figure 4.4). The steam extraction points would not permit higher steam flow rates than the designed values due to the cross section. For this reason options *A, B, C, E, F*, and *G* are no longer considered in this study. Steam extractions from the life steam pipe and the cold reheat pipe would lead to an imbalance of thermal load in the boiler. Moreover, taking out steam from points at the beginning of the steam expansion path would affect downstream the rest of the stages. Therefore, the crossover pipe (*D*) between IP and LP turbines is usually the preferred option [35].

Since up to 2/3 of the LP steam is consumed for the reboiler, the LP turbine section must be adjusted. Steam is condensed at the reboiler and sent back as saturated liquid to the feedwater path. This extraction modifies the steam flow rates in the LP turbine, condenser and LP feedwater pre-heaters diverting these components from the designed operation and thus, reducing efficiency.

Modifications in the flue gas path are the inclusion of the additional desulfurization plant FDG, discussed in section 4.1.1, to keep SO_x levels below 10 ppm (lower than the limits imposed by current environmental regulations), pipelines and auxiliary equipment.

4.5. Capture Ready Power Plants

The European generation fleet is already being modernized[12], but CCS is not yet mature for commercial use. In a wise approach to this reality, some engineering companies are offering *capture-ready* new-built power plants, making possible later retrofit of CCS easy. The critical idea for this approach is to avoid lock-ins which could exclude or obstruct use of future developments in the capture plant.

According to LUCQUIAUD [26], a capture-ready power plant designed for one certain initial power output and then retrofitted could reduce temporally steam extraction rates (even to zero) by through bypassing the post-combustion capture system to increase the gross power output. This potential to rapid shift operation mode brings additional flexibility to the power station could be a valuable asset for the future electric market operation [26].

For this study, we enumerate a number of essential requirements for a capture-ready plant published by the International Energy Agency in the technical report *CO_2 Capture Ready Plants* [17].

- Plant location: close to a CO_2 storage site and possible route for CO_2 transport.
- Layout: Enough space for capture equipment, blowers, additional FGD and accesses to critical locations for connections to be made.
- Cooling water: Include possible cooling water requirements.
- Steam turbine modifications: To enable possible future extraction points if steam requirements for solvent regeneration change.

Figure 4.5 shows a patent solicitude property of Alstom Technology for an IP turbine manufactured with extra lengths in its rotor and casing to enable the later addition of extra turbine stages. Once installed, these extra stages increase turbine expansion ratio and the volumetric flow rate at the crossover IP/LP pipe. By this modification steam will be provided to the capture plant at lowest pressure and temperature allowed by future solvents. Thus, minimum losses will be achieved [2].

4.6. Potential for Process Optimization

Important efforts are being done by companies and institutions to speed up the CCS development and make it commercially viable by 2020. These efforts are focused on three main areas:

- **Equipment optimization**: to enable a large scale operation, costs reductions, new materials with better performance as improved packaging for the absorber/desorber column.
- **Process optimization**: to find the optimal operation conditions, new less energy-intensive process configurations, and high integrated design between the capture plant and the power plant.

[12] The IEA 2006 World Energy Outlook expects 5087GW of new and replacement power plants, mostly using fossil fuels, between 2005 and 2030.

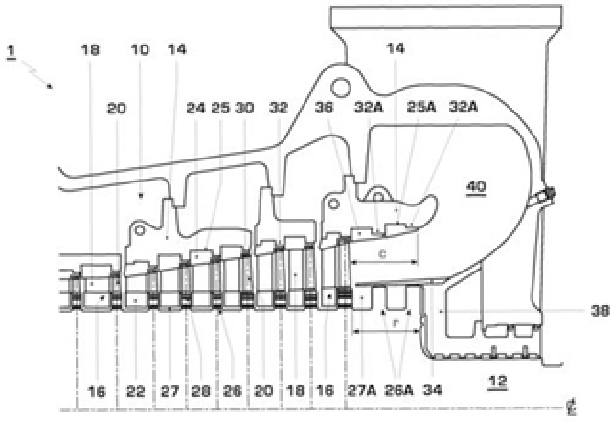

Figure 4.5: Steam turbine designed to facilitate late modification for operation with power plant incorporating carbon capture facilities. Source: WIPO

- **Solvent optimization:** As it was already outlined in section 4.2.1, solvent regeneration is the major consumption within the capture plant. Finding new solvents with better performance is one of the major challenges to enable the required scale-up and situate post-combustion as the most attractive economic solution.

Absorption process development status	**Unit**	**Standard process**	**Improved process** (state of art)	**Third solvent Generation**	**Fourth Solvent Generation**
Desorption enthalpy	MJ/kmolCO_2	80	70	55	30
Cross HTX pinch point	K	15	10	5	3
Solvent flow	$m^3/ton CO_2$	20	10	8	4
Reflux ratio	tonH_2O/tonCO_2	0,7	0,6	0,4	0,1
Thermal energy	**GJ/tonCO_2**	**4,56**	**3,31**	**2,29**	**0,95**

Table 6: Potential solvent and process optimization [10].

Table 6, a continuation of table 4, shows the expected thermal energy requirements for different generations of solvents. Third and fourth generation represent solvents that gradually will include all the improvements mentioned in sections 4.2.1 and 4.3.

5. Introduction to the Simulation

Chapters 2, 3 and 4 have detailed theoretical aspects of steam power plants and capture storage technology, specifically post-combustion. These chapters have been structured to give special focus towards efficiency and energy consumption of the different systems involved, and a number of conclusions can be extracted from them. High power plant baseline efficiencies are important for the optimal operation of a capture system. Energy requirements of post-combustion are high but can be minimized first, with the use of an advanced capture process and last but not at least, with optimal integration between power and capture plants.

First point represents an important field for researchers and shows high optimization potential (see section 4.6). However, this approach is not contemplated in this thesis. Besides, since post-combustion is in essence a chemical process, further study of this area would require other tools and more suitable software packages like Aspen Plus®. For this reason, the capture plant has been modeled as a *"black box"* implementing only those outputs, inputs and other parameters that could be useful for a proper study of plant integration.

Second aspect, integration analysis is the aim of this study. The following chapters are devoted to the analysis of three study cases: as the base case, a state-of-art steam cycle power plant without carbon capture, second, the reference power plant with capture, and third, the reference power plant with integrated capture. By comparing these cases, further study of integration potential can be done, and benefits of the integration can be measured.

In this case, EBSILON® Professional represents the optimal software solution, allowing the design of a rigorous model and to obtain accurate results. Thus, all cases will be modeled and simulated with EBSILON® within the next chapters.

Chapter 6 offers a brief overview of EBSILON®'s main features. In chapter 7, the power plant with both water/steam cycle and flue gas path will be modeled. Chapter 8 is devoted to the model of the post-combustion capture plant and its effects over the power plant without integration. Once the reference case with no integration is calculated, chapter 9 will detail integration possibilities and improvements achieved with them.

6. Model and Simulation with EBSILON Professional

EBSILON® Professional is one of the most used mass and energy balance calculation software in the German speaking Europe. It demonstrates high convergence stability, high calculation velocity and is adapted to Microsoft® environments. EBSILON® possesses all the features required for this study and represents the optimal tool for this work. This chapter briefly summarizes the main features of this software.

6.1. Basic Characteristics

EBSILON® is the abbreviation for "**E**nergy **B**alance and **SI**mulation of the **LO**ad response of power generating or process controlling **N**etwork structures". It is used for engineering, acquisition, planning, monitoring and plant optimization. It permits the arrangement of individual components, component groups, sub-systems and complete systems within closed or open cycles. Standard components and programmable components (*EbsScript* with user defined behavior) can be used together enabling a precise simulation.

For the calculation it uses a mathematical kernel of EBSILON®, a closed solution algorithm based on a sequential solution method that demonstrates good convergence properties. EBSILON® calculates water/steam processes, combustion processes, gas turbine processes and CHG processes. Fluid properties are predefined; steam properties are based on the IAPWS-IF97 or the IF67 tables, and air/flue gas properties are obtained by c_p-polynomials.

6.2. Working Environment

Main toolbars are shown in the figure 6.1. The standard toolbar allows file management and other windows classical functions. Component bar, for access to components grouped by categories, such as turbines, pumps, heat exchanger, etc. Ebsilon bar, for starting simulations, validations and error analysis. Profile bar, for off-design analysis, allowing multiple profiles for different partload cases.

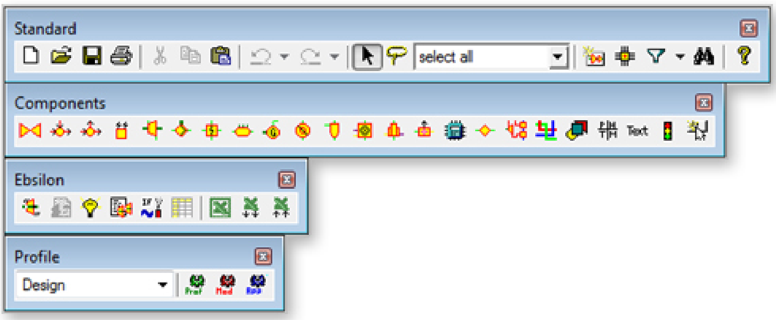

Figure 6.1: Main EBSILON® Professional tool bars

6.3. Object Types

EBSILON® operation is based on objects. The main objects are:

- **Components and Pipes:** Components are the main building blocks of a cycle, with multiple inlets and outlets, each one with a specific "fluid type". By adjusting the different specification values, each component adjusts to the individual case. Pipes connect components within the simulation.

Controllers: controllers are components used to achieve a specific value of one parameter in a selected location of the cycle. A controller compares the requested value (reference value set by the user) and the actual value of one parameter, and iterates correcting a second parameter till the reference value is reached. These are important components for the simulation, and have been used for the steam generator and air preheater modeling. Section 7.1.2 details precisely those controllers implemented within the simulation.

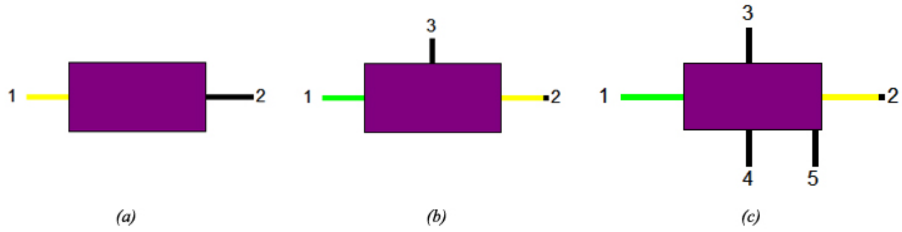

Figure 6.2: Controller with (a) internal set value, (b) external set value, (c) external set value and switch

- **Macros** are a predefined set of components and or pipes with specific performance, such as the gas turbines form the gas turbine library.
- **EbsScript**: EbsScript is a tool for EBSILON® that enables to use the input, output and calculation capabilities automatically, and to combine them with the specific user calculations. EbsScript uses PASCAL syntax and has access to all calculation parameters, specification values, characteristics and result values for all components, pipes and profiles. One script have been programmed in this study for the simulation of the capture plant. Appendix A explains widely its operation.
- **Display objects:** OLE Objects, Value Crosses, Text fields and Graphical elements can be used for displaying results.

6.4. Design Mode

The Design mode is where the process is modeled. The next steps have to be followed for the design of any particular process:

- **Adding components**: addition of all components necessary for the model, selecting them from the Component bar.
- **Connecting components**: once the components are situated, next step is to connect them. Each component has a number of connections. The purpose of these connections is displayed in the properties window of the component (figure 6.3). To connect components, appropriate pipes have to be selected. Each type of pipe has a different color.
- **Defining specific values**: to characterize the topology of the cycle. Specific values can be defined in the component properties window (figure 6.3) or directly on the pipes with the component "Measured value input".
- **Simulation and error analysis**: run the simulation. EBSILON® display results and errors in the simulation. Errors analysis informs about missing data, overdeterminations and other kind of errors that stop the simulation.

- **Displaying results**: Results are displayed in multiple ways, directly in the components or the pipes, or by the use of cross values.

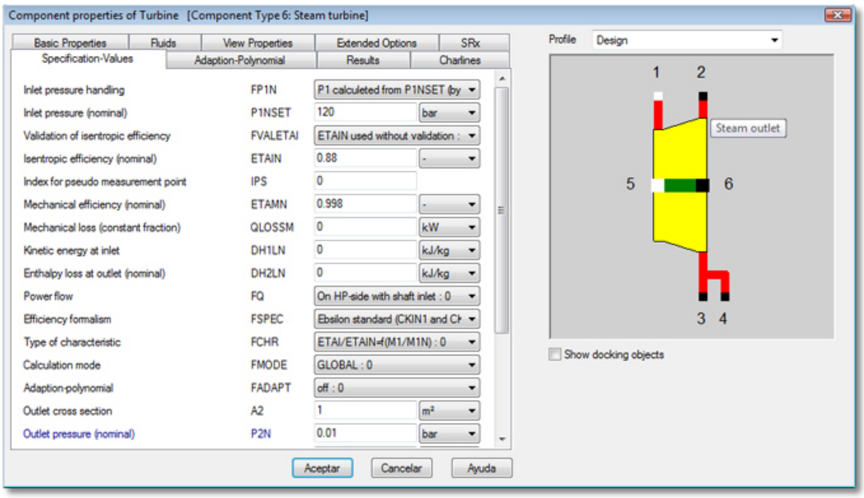

Figure 6.3: Properties of the component "Steam Turbine"

6.5. Off-Design Mode

The cycle is modeled initially in *Design* mode, where all components are in nominal conditions defined by nominal characteristics. EBSILON® allows the analysis of partload cases using the *Off-Design* mode. Moreover, with the *Profiles* feature it is possible to define several off-design calculations.

Each component contains predefined *charlines* (see figure 6.4). Charlines are characteristic lines that define the performance of the component in Off-Design mode. As an example, the isentropic efficiency of a turbine in partload depends on the inlet mass flow M1. The charlines relate two dimensionless ratios; the performance of the component (in this case ETA/ETAIN) as a function of other parameter (in this case M1/M1N).

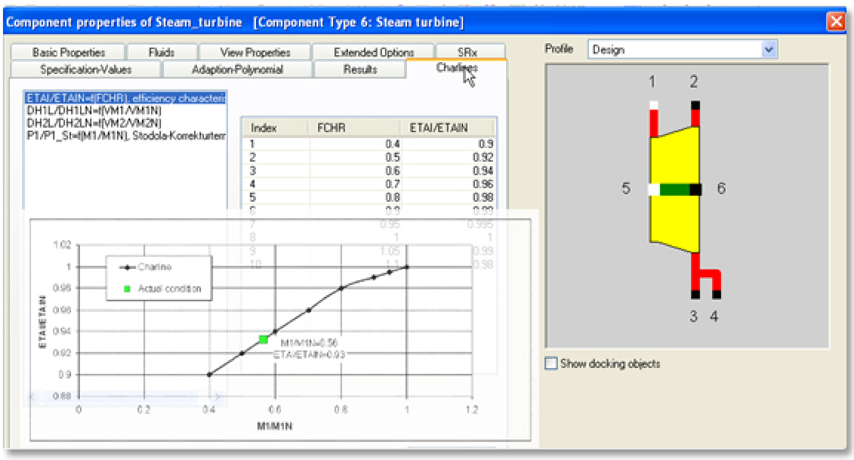

Figure 6.4: Charlines tab for component "Steam Turbine" for off-design operation

7. Model and Simulation of the Steam Power Plant

Chapter 2 offers, from a theoretical approach, the evolution from the ideal Rankine cycle to the current state-of-art steam power plants, and a complete overview of their the main features. This perspective allows us to understand and validate the different components to model. Within this chapter, the power plant selected for the simulation will be described, and all following stages for the simulation will be detailed.

The power plant chosen for this thesis was the Reference Power Plant North Rhine Westphalia (RPP NRW) [31]. We considered this coal fired power plant the most suitable for carbon capture retrofitting for two main reasons; first, the reference power plant applies new technologies that will be implemented by the time CCS becomes commercially viable, and second, the high efficiency achieved of this power plant, around 46% (LHV).

7.1. Description of the Reference Power Plant

The concept study Reference Power Plant North Rhine Westphalia is the result of a joint research project coordinated by VGB PowerTech and carried out during 2002-2004 by plant constructors and plant operators[13], with technical support of several institutions in aspects related to the economy, ecology and structural policy of the project. This integral study developed an optimized concept of a steam power plant, applying innovations and new technologies, with the goal of increasing efficiency and reducing emissions with minimized investment cost.

The concept of the RPP NRW is based on a hard coal fired 600 MW plant with optimized plant technology and net efficiency of 45,9%. This high efficiency situates NRW reference power plant clearly above the average of hard coal power plants currently in operation in the OECD, with an average efficiency of 36% [18]. Table 7 shows RPP NRW key technical features.

	Value at Nominal Conditions
Gross power output	600 MW
Heat input by fuel	1210,3 MW
Gross efficiency (LHV basis)	49,5%
Net efficiency (LHV basis)	45,9%
Main steam paramenters at turbine inlet	285 bar / 600°C / 620°C
Condenser pressure	45 mbar

Table 7: Main features of the Preferred Variant of the RPP NRW [31]

7.1.1. Water/Steam Cycle

Turbine generator set The selected turbine modules belong to the Siemens steam turbine H-I-L product line. This turboset consist of separate HP, IP and LP turbine sections with a total length of 16 meters. Main features of the turboset are detailed in table 8.

HP turbine is designed as barrel-type turbine, capable to cope with ultra-supercritical life steam conditions. Components exposed to high temperatures such as the HP inlet barrel, rotor and inner casings are made of 9-12% CrMoV steel. This design includes an inner casing with internal bypass

[13] Plant constructors: Babcock Hitachi Europe and Siemens AG. Plant operators: E.ON, Mark-E RWE Power and STEAG

cooling system for a more flexible operation (start-up and load changes). **The IP turbine** takes reheat steam at conditions of 620°C and is designed as a single turbine with double flow exhaust (see figure 2.13). To handle the high steam temperature the rotor and inner casing are also made of 9-12% CrMoV steel and a novel cooling technology called vortex cooling is used to reduce rotor surface temperature up to 20 K. In addition, first blade stages are made of Nickel-based-alloyed steel to withstand the centrifugal load in combination with high temperatures. **The LP turbine** consists of up to three a double flow with horizontal split casing turbines (see figure 2.13). The typical steam conditions are up to 7 bar and 350°C. The steam will expand to the condenser at condenser pressure of 45mbar.

The generator is a two-pole generator, directly coupled to the turbine. With direct water-cooled stator windings, a hydrogen-cooled rotor, static excitation, a two-channel digital voltage regulator and the necessary auxiliary systems.

	Value at Nominal Conditions
Live steam parameter	285 bar / 600°C
Reheat parameter	60 bar / 620°C
LP turbine inlet steam conditions	5,5 bar / 269°C
Condenser pressure (cooling tower)	45 mbar
Steam turbine model	Siemens H60/I60/L2x16 m^2

Table 8: RPP NRW turbine set key features [31]

Water/steam cycle The water steam cycle consists basically of the steam turboset with the single pressure condenser, the main condensate pumps, the low pressure preheating line, the feedwater tank (deaerator), the feedwater pumps, the high pressure preheating line with external desuperheater and the supercritical steam generator. The simplified process flow diagram shown in figure 7.1 establishes the main water/steam scheme; usual paths followed during stationary operation are shown in color while piping and auxiliaries required for load changes, start-up, shutdown, maintenance or others are displayed in black and white. Turbine extractions to drive the HP feedwater heaters are shown in *pink*, *yellow* corresponds to the bled directed to the deaerator. *Green* piping are steam extractions to the LP feedwater heaters. *Blue* represents the usual feedwater path. Following this path the feedwater is heated up to 303,4°C, through eight preheaters and one desuperheater, before entering the steam generator. The main components of the feedwater preheating system are detailed in table 9.

Component	**Characteristics**
Feedwater heaters LP1 and LP2	located in the condenser neck as a Duplex-heater (figure 2.14)
Feedwater heater LP3	Closed-type drain pumped forward
Feedwater heater LP4	Closed-type drain cascaded backwards With subcooling section
Deaerator	Open-type feedwater heater
Feedwater heaters HP1, HP2 and HP3	Closed-type drain cascaded backwards With superheating and subcooling section
Final feedwater temperature	303,4°C

Table 9: RPP NRW feedwater preheating line [31]

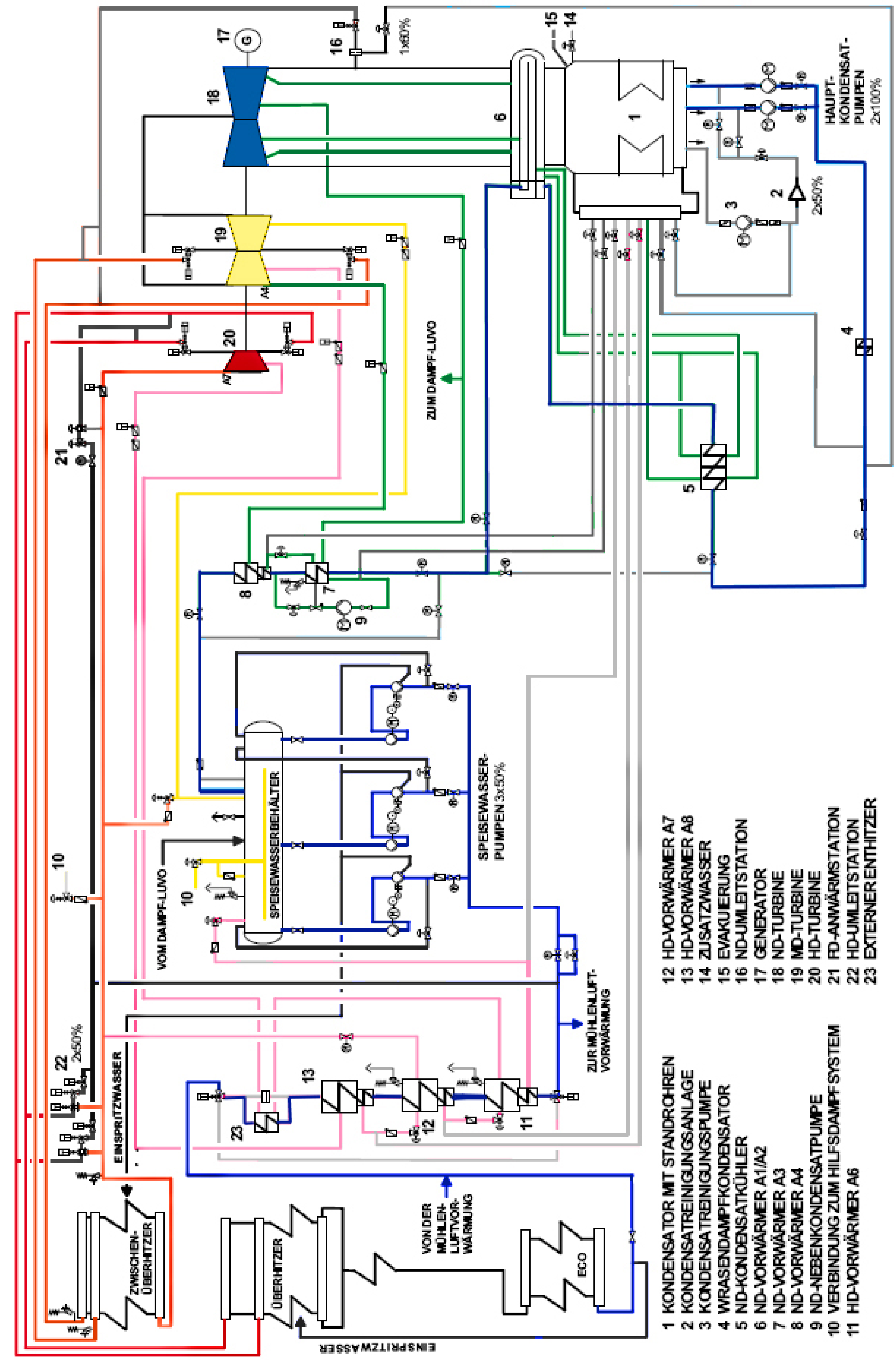

Figure 7.1: Water/steam scheme in the RPP NRW [31]

7.1.2. Flue Gas Path

Steam generator The Benson supercritical steam generator is a Once-through type with tower design (vertical evaporator tubing). It allows great flexibility in selecting the number of burners and pulverizers. The steam generator reaches 95% efficiency at design conditions. Up to 435 kg/s of main steam can be generated at nominal conditions. For the combustion an air ratio of 1,15 is considered. In the steam generator pressure is mantained under atmospheric levels for security reasons.

The values of the process parameters and the boiler efficiency depend on the coal being burnt. Table 10 shows the quality for the selected coal and tolerable limits for an appropriate operation of the steam generator.

	Unit	**Design Values**	**Tolerable Band**
Calorific value	MJ/kg	25,0	21,0 to 29,0
Water	%	7,5	7,0 to 18,0
Ash	%	14,0	5,0 to 22,0
Volatile Components	%	30,0	23,0 to 47,0
Nitrogen	%	1,5	< 2
Sulphur	%	0,6	$< 1,5$
Chlorine	%	$< 0,01$	$< 0,3$
Grindability	°H	50	40,0 to 80,0
Softening point	°C	1270	> 1150

Table 10: RPP NRW Coal characteristics [31]

Flue gas path In the air/flue gas path coal and air are preheated and subsequently converted into hot flue gas in the furnace. The ambient air is preheated and delivered to the furnace by a fan while dry ash is extracted from the bottom at 300°C. Air preheating is carried out by a steam-air preheater and a *Ljungström* type air preheater to reach 350°C. Using a *mill air-heat recovery*, air can be preheated up to 355°C . The excess heat from the air is then extracted in a heat exchanger and transferred to the feedwater until air temperature is again 350°C. After the air preheating, flue gas temperature is above 115°C and is conducted to the electrostatic precipitators to remove particulate matter. By an induced draught fan the flue gas is delivered to the flue gas desulphurisation plant (FGD) and finally emitted at a temperature of approximately 50°C into the atmosphere.

The flue gas cleaning equipment reduces mainly NO_x, dust and SO_x emissions in accordance with the European directive *"Directive of the European Parliament and of the Council on the limitation of emission of certain pollutants into air from large combustion plants"*. A new German regulation, the *"Ordinance on Large Combustion Plants"* was not yet completed by the time the RPP NRW concept study was accomplished. Therefore, RPP NRW applies the European limits, displayed in the table 11. However, the concept sudy RPP NRW concludes that the implementation of the new regulative is considered technically without serious impact on the economics of the reference power plant [31].

Component	**Unit**	**EU Directive**	**German Directive**	RPP NRW
Sulphur dioxide (SO_2)	mg/m^3	< 200	-	-
Sulphur oxides (SO_2 + SO_3) SO_x	mg/m^3	-	< 200	< 200
Nitrogen oxides (NO + NO_2) NO_x and NO_2	mg/m^3	< 200	< 200	< 200
Dust	mg/m^3	< 30	< 20	< 30

Table 11: RPP NRW emission limits [31]

7.2. Model and Simulation

To enable an appropriate analysis of the power plant some boundary conditions have to be set. Selecting constant power output simplifies the analysis of the power plant performance. Nevertheless, the aim of this study is the addition of a carbon capture plant and maintaining constant the power output would require variations in the amount of coal used in each case and as a direct consequence the amount of CO_2 to separate. Such variations would hinder the correct analysis of the whole model. For this reason, fixing the coal mass flow is the most suitable boundary condition from a CCS approach. The approximated coal mass flow for the RPP NRW at design conditions (base load) is 48kg/s [31].

Ambient conditions also affect thermodynamic performance of power plants. The reference power plant RPP NRW has been calculated for 11°C of atmospheric air and designed for inland location, considering therefore a natural-draft wet cooling tower. Coastal locations with fresh water from the river or the sea would allow lower condensing pressures and thus, net efficiency up to 47% (LHV) could be achieved [31].

7.2.1. Water/Steam Cycle Model

Once described the steam power plant and set the boundary conditions, the first step of the model is the water steam cycle. As in chapter 2, the procedure to follow with EBSILON® starts from the simplest Rankine cycle and step by step modifications are added. Run the simulation each time is important to ease the error analysis. In accordance with this procedure, the model started with a simple Rankine cycle consisting of one steam generator, one single turbine, condenser and feedwater pump. The default isentropic efficiency (90%) and mechanical efficiency (99,8%) for the turbines have been used, these values can be considered state-of-art.

Reheat To improve efficiency reheat is modeled. Before it is necessary to split the single turbine in at least two turbines. The reheated steam is directed to the second one. To progress in our model, the three turbines (HP, IP and LP) are split at this point. Figure 2.4 shows the effect of reheat over the cycle efficiency as a function of the reheating pressure. This function is maximized around 20-25% of the life steam pressure, in this case 285 bar. RPP NRW establishes a reheat pressure of 60 bar, which in accordance with the theory represents 21% of the live steam pressure.

Regeneration Regeneration is the next efficiency upgrade applied to conventional power plants (see section 2.1.2). In RPP NRW regeneration consists of a low pressure line of feedwater heaters, a high pressure line and a open-type feedwater heater operating as deaerator. (see table 12).

	Extraction points
Low pressure turbine	3 for LP1, LP2 and LP3
Intermediate pressure turbine	3 for LP4, DEA, and HP1
High pressure turbine	2 for HP2 and HP3

Table 12: RPP NRW extraction points for each turbine. DEA = Deaerator, LP = Low pressure feedwater heater, HP = High pressure feedwater heater [31]

Steam extraction points selection To enable regeneration, steam has to be extracted at different pressures from the turbine set. Thus, the next required step in the model is to split the turbines

Turbine	Extraction	Pressure (bar)	X	Heater Type	Sections
LP turbine	LP1	0,20	0,94	Closed cascaded	COND, SUB
	LP2	1,00	1	Closed cascaded	COND, SUB
	LP3	2,50	1	Closed pumped	COND
IP turbine	LP4	5,80	1	Closed cascaded	DSHR, COND, SUBC
	DEA	15,00	1	Open Deaerator	-
	HP1	30,00	1	Closed cascaded	DSHR, COND, SUBC
HP turbine	HP2	60	1	Closed cascaded	DSHR, COND, SUBC
	HP3	82	1	Closed cascaded	DSHR, COND, SUBC

Table 13: Selected extraction points for the RPP NRW regenerative cycle. COND = Condensing section, SUB = Subcooling section, DSHR = Desuperheating section, DEA = Deaerator

in several stages, one for each extraction needed. Section 2.1.2 offers a detailed description of how can be calculated optimal steam extraction points for the feedwater heaters. In summary, optimal pressures are those equivalents to the saturation temperatures that minimize boiler-preheating point and preheating point-condenser temperature differences. However, in actual power plants other considerations have to be considered and may dictate the exact positions of the feedwater heaters. Since there is no information available about expansion ratios of the turbine stages for the RPP NRW, these have been selected in order to obtain the closest points to the optimal location for the feedwater preheaters and to obtain a model equivalent to the RPP NRW.

Due to the supercritical conditions reached in the RPP NRW, it is not possible to apply exactly equation (2.3). There is no boiling temperature and neither boiling pressure, but we can obtain an approximation using the critical steam temperature, 373,9°C and a condensation temperature of 31°C, corresponding to the condensation pressure of 45 mbar. Following equation (2.3) for eight feedwater heaters the approximated temperature increase in each feedwater preheater is around 34°C. However, as already mentioned, an extraction point is dictated at reheat conditions.

Table 13 summarizes the selected points for the steam extraction of each feedwater heater. This configuration fits properly with the available data from the reference power plant, efficiency achieved (49,50% gross and 45,91% net) and the feedwater temperature at the entrance of the steam generator (304,2°C) are acceptable values compared with the concept study.

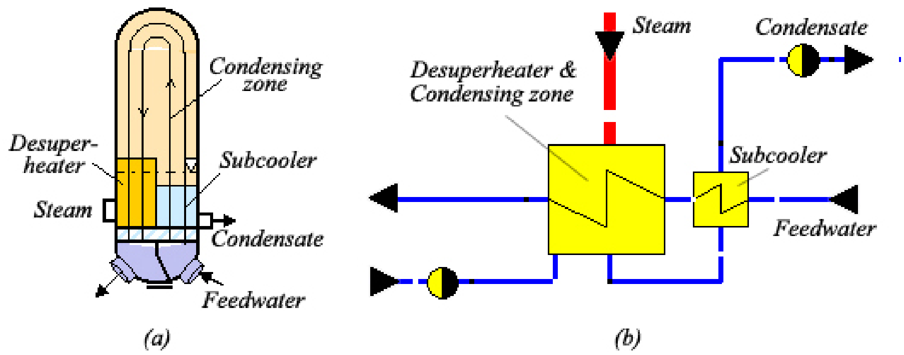

Figure 7.2: EBSILON® model for a closed feedwater heater

Closed feedwater heaters are shell and tube vertical or horizontal heat exchangers (see figure 7.2a), with up to three sections. EBSILON® allows a proper model of closed feedwater preheaters using components 10 *"Heating condenser"* and 27 *"Aftercooler"*. Component 10 calculates by itself the required steam quantity and includes desuperheating zone, but not subcooling. To model the subcooling section an "Aftercooler" has to be added, Figure 7.2b.

In all cases, the upper terminal temperature difference *DT3S2N* has to be set. In case of superheated steam, the primary medium can become hotter than the condensate, in this case the upper terminal *DT3S2N* is a negative value (See figure 2.8). According to Wakil [8], current state-of-art heaters reach values of *DT3S2N* between 0°C and -3°C. Therefore the value of -3°C has been selected for feedwater heaters with desuperheating zone and 3°C for the rest of the feedwater heaters.

Once the Rankine cycle includes reheat and regeneration system, is possible to run the simulation of the complete water/steam cycle. Figure 7.3 shows the results of the simulation for the base load case 48kg/s coal mass flow.

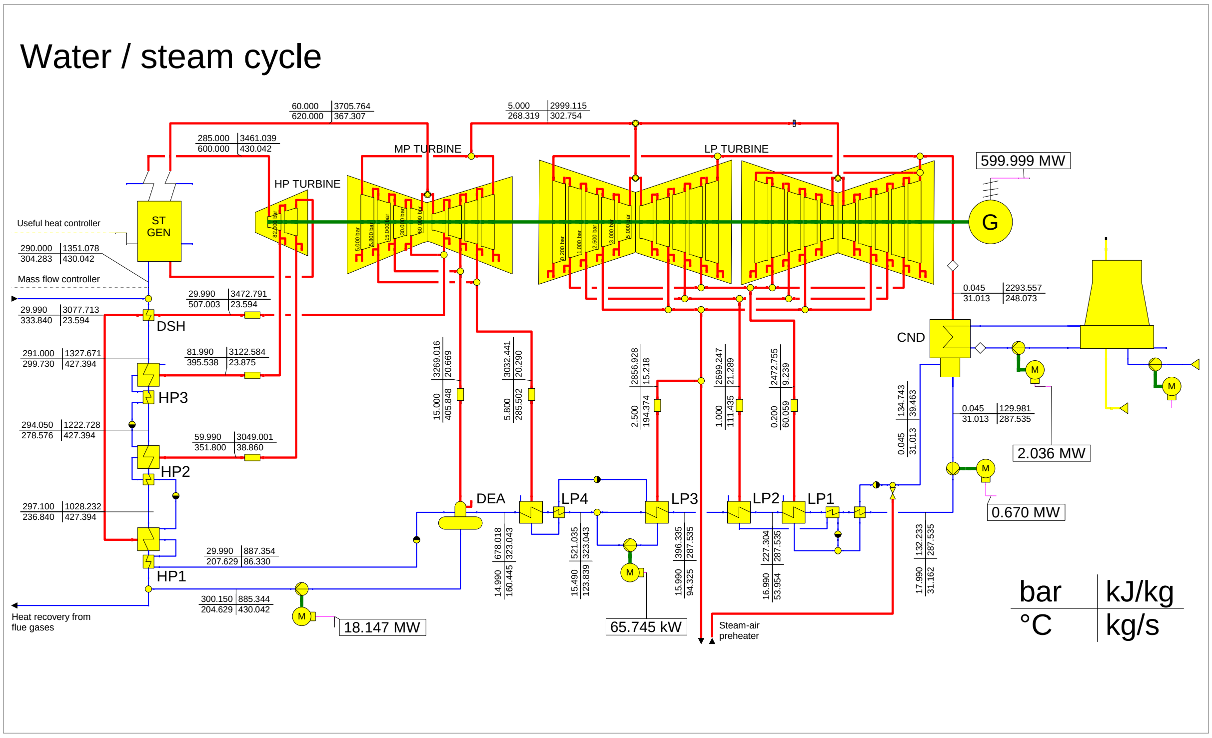

Figure 7.3: Water/steam cycle model with EBSILON® for base load: 48kg/s coal mass flow

7.2.2. Flue Gas Path Model

Section 7.1.2 details the main features of the air/flue gas path in the Reference Power Plant NRW. First part to model is the combustion area including component 21 *"Combustion chamber"*, coal characteristics with component 1 *"Boundary values"* and air preheating system.

Component 21, "Combustion chamber" is the calculation module for combustion chambers and fluidized bed firing. This component used together with the *"Steam generator"* conform a simplified model of the Benson once-through steam generator implemented in RPP NRW. Thus, it is not necessary to model all sections of the steam generator, such as *"reaction zone"*, *"flue gas zone"*, *"bundle heating surfaces"*, *Economizer*, *superheaters*, *reheaters*, etc. This simplified model is based on one logic connection between both components; the *"generated thermal heat"* for the combustion chamber is an output logical pin, and indicates the final amount of heat transferred to the working fluid, while for the steam generator the logical input represents the "thermal boiler duty", value equal to the *generated thermal heat* in the combustion chamber.

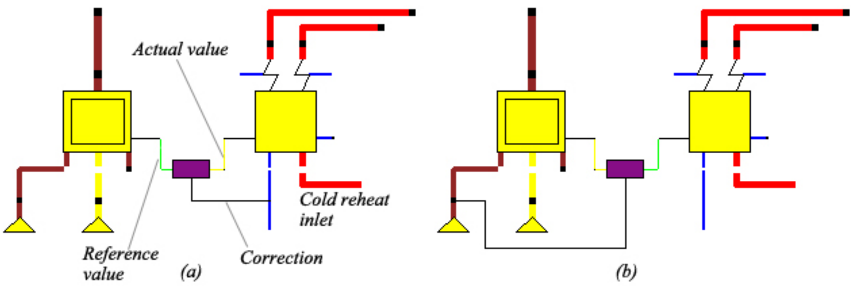

Figure 7.4: Steam generator simplified model controlled to keep constant (a) the generated thermal heat and (b) the thermal boiler duty

To control both components a controller is implemented. Figure 7.4 details the two possible ways to control the modeled steam generator according to the appropriate boundary condition for each analysis. The scheme represented in the figure 7.4b modifies the coal mass flow to reach the desired heat input to the steam generator. This configuration enables the selection of a constant power output and hence, further study of the water steam cycle. In our case, it is necessary to maintain the flue gas parameters and therefore the coal mass flow. Figure 7.4a shows how the controller will vary the feedwater mass flow to reach the desired *thermal boiler duty* for a specific flow of coal.

For a proper model of the steam generator is necessary to modify the main parameters in the combustion chamber (figure 7.5): air ratio *ALAMN*, temperature of exit flue gas *TBEDN* and combustion efficiency *ETABN*. Temperature *TBEDN* corresponds to the temperature at the control surface:

- In case of a complete model of the steam generator, *TBEDN* is the temperature in front of the first heat exchanger in the direction of the flue gas downstream.
- If no additional components are modeled in the direction of the flue gas, but instead the heat exchanger is assumed within the component *combustion chamber* (without considering its detailed structure), *TBEDN* can also be assumed as the gas temperature at the outlet of the boiler

TBEDN changes on the basis of a *characteristic line* (see section 6.5) in relation to the load. This mean that for partload cases the exit flue gas temperature varies. Our model for the RPP NRW steam generator will establish *TBEDN* as the flue gas temperature just before the *DeNOx* plant. This temperature will reach 360°C at base load operation and will decrease gradually in accordance to the reduction of coal mass flow.

Coal properties can be modified from the *boundary value* properties window, *Material fractions* tab (figure 7.6). EBSILON® includes a complete database with a wide range of coal types, however, for a rigorous simulation, the properties of table 10 were defined for the model.

The air preheating system, is modeled as detailed in section 7.1.2. In order to calculate the air preheating steps the use of controllers is necessary: controller 2 (CNT2) calculates the exact steam mass flow required to reach 355°C after the flue gas-air preheater, controller 3 (CNT3) calculates

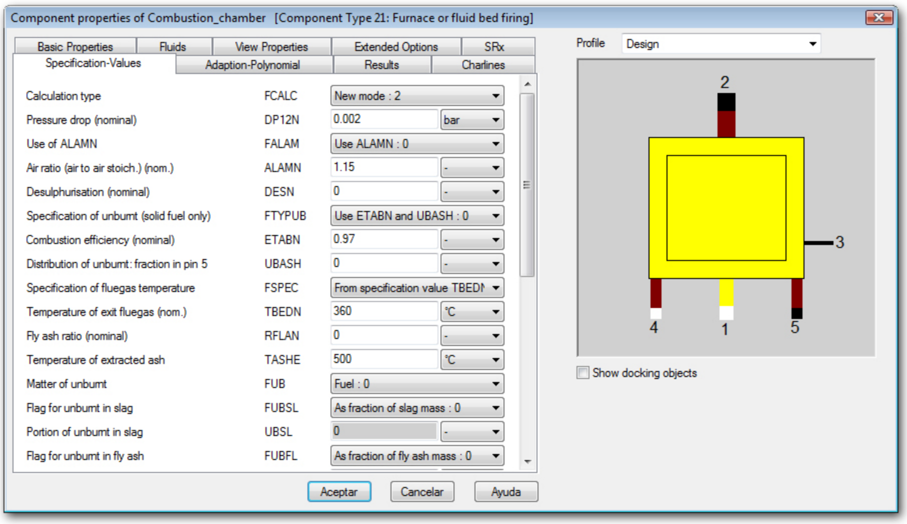

Figure 7.5: Combustion properties selection in component 21 "*combustion chamber*"'

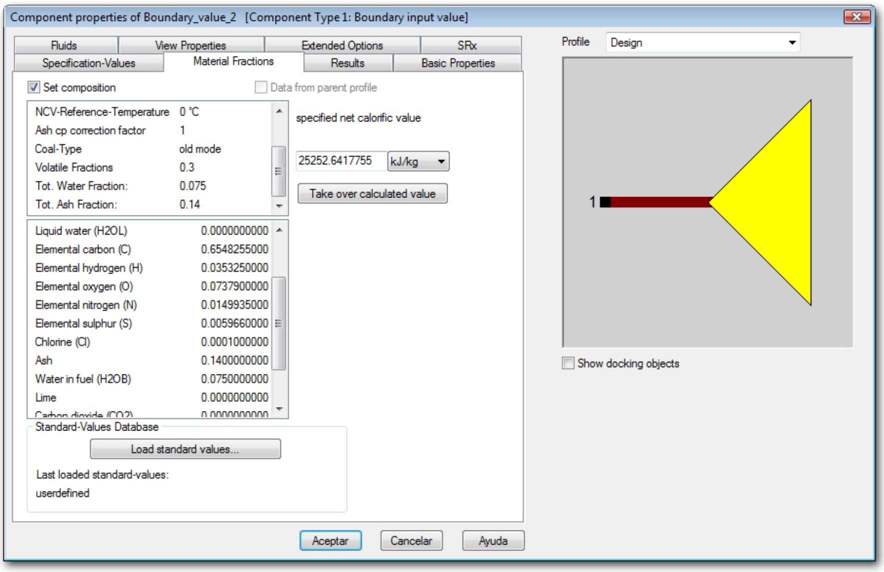

Figure 7.6: Coal characteristics selection in component 1 "*Boundary value*"

the required water mass flow to extract heat from the flue gases untill the heated air reach 350°C.

After the air preheater flue gas in RPP NRW is conducted to the denitrification plant (DeNOx), the electrostatic precipitator and the flue gas desulphurisation plant (FGD) to be emited at a temperature of approximately 50°C into the atmosphere. The RPP NRW concept study does not include more information about the cleaning stages than the emissions reductions. To at least approximate their energy requirements, a energy consumer *"Electric motor"* is added, and its consumption linked to the flue gas mass flow by component 36 "*Value transmitter*". Values for the energy requirements of the DeNOx and FGD are obtained from [35].

Air fans are necessary to overcome the pressure drops of the different equipment. The flue gas path includes one air fan, and one induced draught fan at the flue gas path. First blower is designed to assure pressures under atmospheric pressure in the combustion chamber and the second blower overcomes pressure drop of the cleaning equipment. Finally the complete flue gas path has been modeled and integrated with the water steam cycle. The following 7.7 figure shows the flue gas path EBSILON® model.

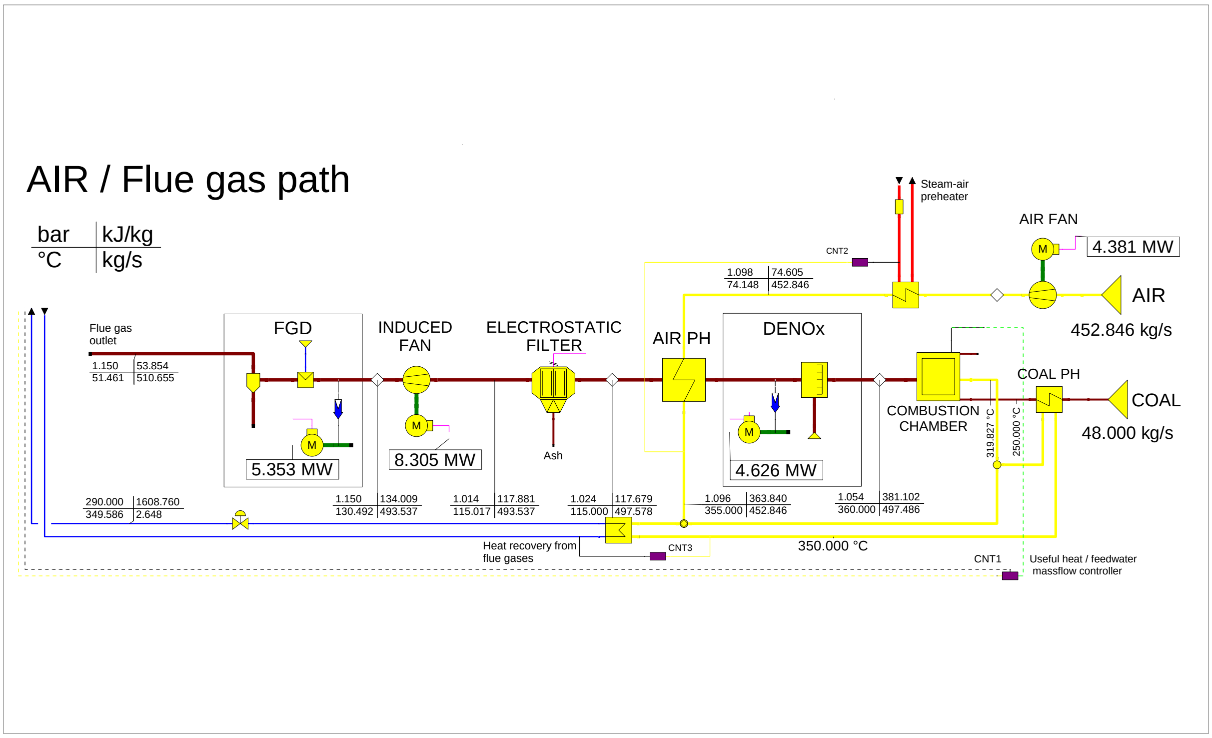

Figure 7.7: Flue/gas air path model with EBSILON® Professional for base load: 48kg/s coal mass flow

7.2.3. Baseload Simulation

The flue gas path and the water/steam cycle are linked mainly by the logic control between the combustion chamber and the steam generator. Besides, one additional steam extraction is directed to the air preheater system and after the flue gas air preheater some heat is transferred again to the working fluid by the mill-air recovery heat exchanger.

The selection of the steam extraction point for air preheating was chosen taking into account different aspects: the lower steam quality extracted the less influence over the water steam cycle efficiency, on the other hand, steam extracted has to be able to increase air temperature to the level requested by the flue gas-air preheater. Another technical constraint appears in the RPP NRW; it is not possible extract steam from the last two stages since these bleeds feed LP1 and LP2, which are one Duplex heat exchanger (figure 2.14) inserted into the condenser neck. An extraction from these points would require LP turbine shell modifications. Therefore, the next lower extraction is selected to deliver heat to the steam-air preheater. Extra heat extracted from the flue gas to the air by the use of a mill-air heat recuperation, is high quality heat (more than 350°C) and can be used to heat up a small feedwater mass flow from the HP feedwater heaters line, reducing in some percentage the steam mass flow extracted from the high pressure feedwater heaters line.

Once the model is closed, the power plant RPP NRW simulation results at base load and the real case can be compared to validate the model. Table 14 shows the key parameters of the RPP and its simulation.

	Value at Nominal Conditions	**Results of the Simulation**
Gross power output	600 MW	600,15 MW
Heat imput by fuel	1210,3 MW	1212,13
Gross efficiency (LHV basis)	49,5%	49,51%
Net efficiency (LHV basis)	45,9%	45,91%
Main steam paramenters	285 bar/600°C/620°C	285 bar/600°C/620°C
Condenser pressure	45 mbar	45 mbar
Live steam massflow	435 kg/s	430,75 kg/s
Feedwater final temperature	303,4°C	303,97°C

Table 14: Main features of the Reference Power Plant NRW [31] and the results of the simulation

The model reasonably predicts the mass and energy parameters for the reference power plant NRW. Values for power output, heat input, feedwater temperature and efficiencies are almost the same. However there is a sensible difference, less than 1%, in the life steam mass flow at design conditions.

The available data within the concept study RPP NRW, is not detailed enough to fix all variables in the model, therefore assumptions were made to reach values close to the published information. Following this approach, isentropic efficiency of the steam turbines, combustion chamber efficiency, power generator efficiency and steam extraction pressures among others were estimated from cited literature or from EBSLION® default values. With regard to the life steam mass flow variation shown in table 14, we could find in those estimated values a possible explanation. First, the values for turbine efficiencies are possibly higher than the real case, since a turbine with lower efficiency requires higher steam mass flow to reach the same output power. Moreover, the coal mass flow is not mentioned in the concept study and therefore it has been estimated too. A value of 48kg/s was selected in order to achieve a good approximation of the specified heat input by the fuel. Korkmaz et al [35] who simulated the same reference power plant, define a value of 48,4 kg/s for this parameter. The coal mass flow and combustion chamber efficiency have a direct effect on the generated life steam. Thus, we can think that with more information available, this variation could be rectified.

The results of the simulation are close to the reference power plant NRW and therefore, we consider the model valid to continue the capture plant simulation. Figure 7.8 shows the complete power plant model after running a simulation for design conditions, 48 kg/s coal mass flow.

7.2.4. Partload Simulation

To enable a proper study of the capture process, partload performance has to be analyzed. For this reason, two partload regimes are simulated for the reference power plant. These cases together with the base load simulation will act as reference points for the capture process integration study. Table 15 details the partload cases selected.

When the RPP NRW leaves design conditions, operation mode is partial sliding pressure operation (see section 2.2.1). What it means that the steam generator operates at sliding pressures from 40% partload to design conditions. For loads lower than 40% the pressure is kept constant to avoid

	Partload (%)	Boundary Condition Coal mass flow (kg/s)
Base Load	100	48,00
Part Load 80	80	38,4
Part Load 60	60	28,8

Table 15: Part load cases selected for the simulation

damages in the membrane walls [31].

Under sliding pressure operation mode, the steam temperatures at the HP and IP turbine inlets stay constant, meanwhile the temperatures at the furnace change. Under design conditions heat transfer to the water/steam cycle reduces the temperature of the flue gas to approximately 360°C at the outlet of the economizer. This temperature decreases in partload and so the combustion air preheating.

For this reason, some modifications were necessary to fit the model for part load operation. The controller CNT2, was modified to calculate the necessary amount of heat from the steam bled covering also the partload cases, when the flue gas in the air preheater has lower temperatures. At the same time, controller CNT3 was set to increase the feedwater temperature only to the same temperature that the feedwater exiting the HP feedwater heaters line instead of higher increases that in part load are no longer possible. After this two modifications, the simulation was carried out for both partload cases, and the results are shown in figures 7.9 and 7.10.

80% Partload Reducing coal mass flow to 38,4 kg/s results in a gross power output drop to 447,9 MW_{el}. With regard to the nominal gross power output this case represents at 74% partload. Sliding pressure operation causes the pressure decrease to 224,1 bar, still supercritical conditions. In this operation mode (see section 2.2.1), load is controlled by the steam mass flow rate and pressure is adjusted to the optimal turbine pressure operation for each load. Table 16 details the results for 80% coal mass flow simulation together with 60% and base load cases.

60% Partload At 60% load, coal mass flow is fixed to 28,8 kilograms per second. To face such decrease in heat input to the cycle, sliding pressure operation mode reduces pressure to 197,2 bar. Below 221,2 bar steam parameters are subcritical. Thus, some parts of once-through steam generator operate in the two-phase region. Section 2.2.1 briefly describes sliding pressure operation mode for once-through generators. This study case represents a 52% partload with regard to the gross power output. Figure 7.10 shows, in accordance with section 2.2.1, how while steam line pressure decreases, the life and reheat steam temperatures remain constant.

Study Case	Coal kg/s	Gross Eff %	Net Eff %	Gross MW	Net MW	Steam kg/s	HP Pressure bar
Design Case	48,0	49,51	45,91	600,15	556,48	430,75	285,0
80% Partload	38,4	46,19	42,88	447,94	415,77	332,83	224,1
60% Partload	28,8	43,15	39,76	313,84	289,17	237,88	197,2

Table 16: Results of the simulation for the reference power plant NRW without carbon capture plant

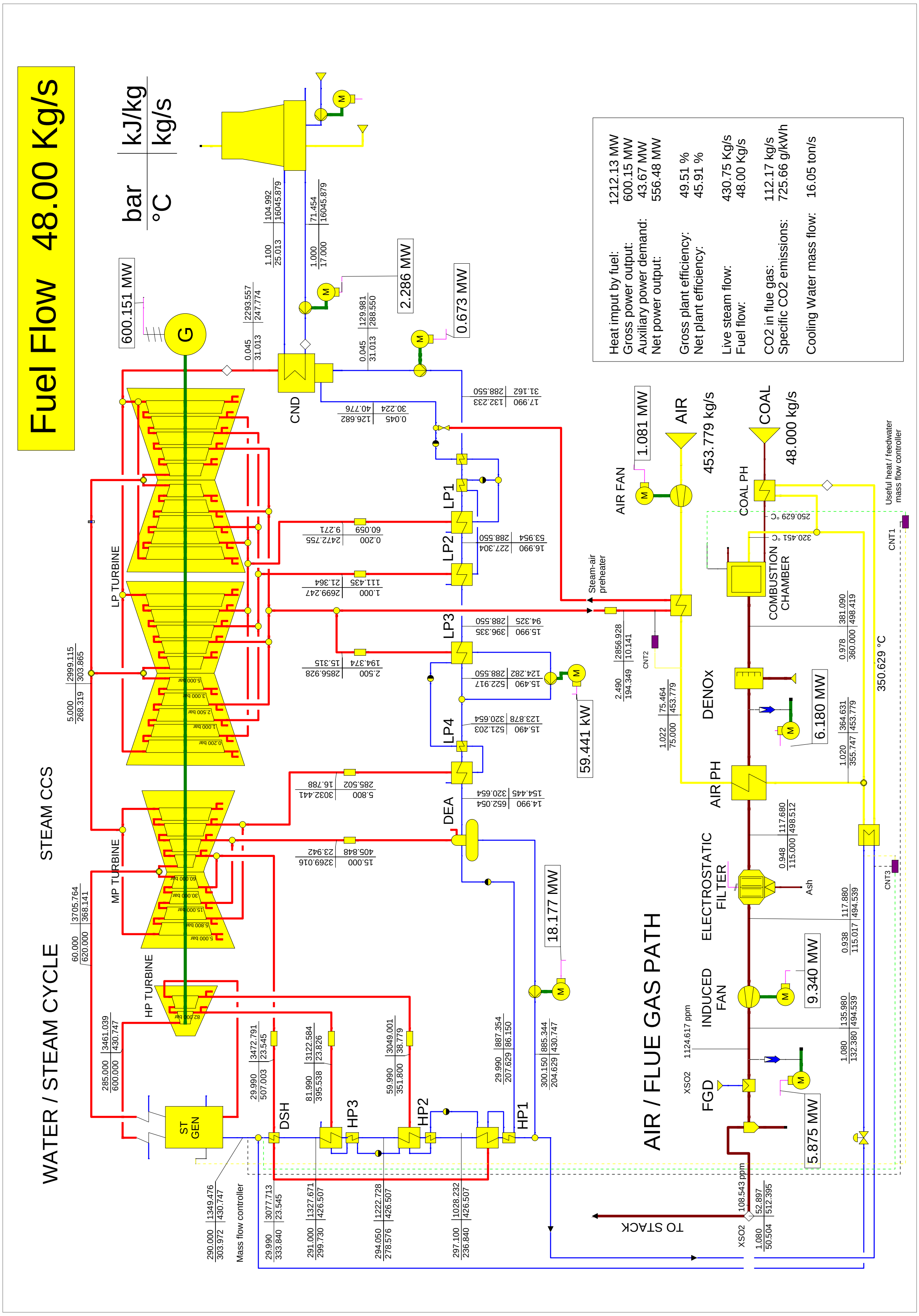

Figure 7.8: Complete RPP NRW model with EBSILON® Professional for base load: 48kg/s coal mass flow

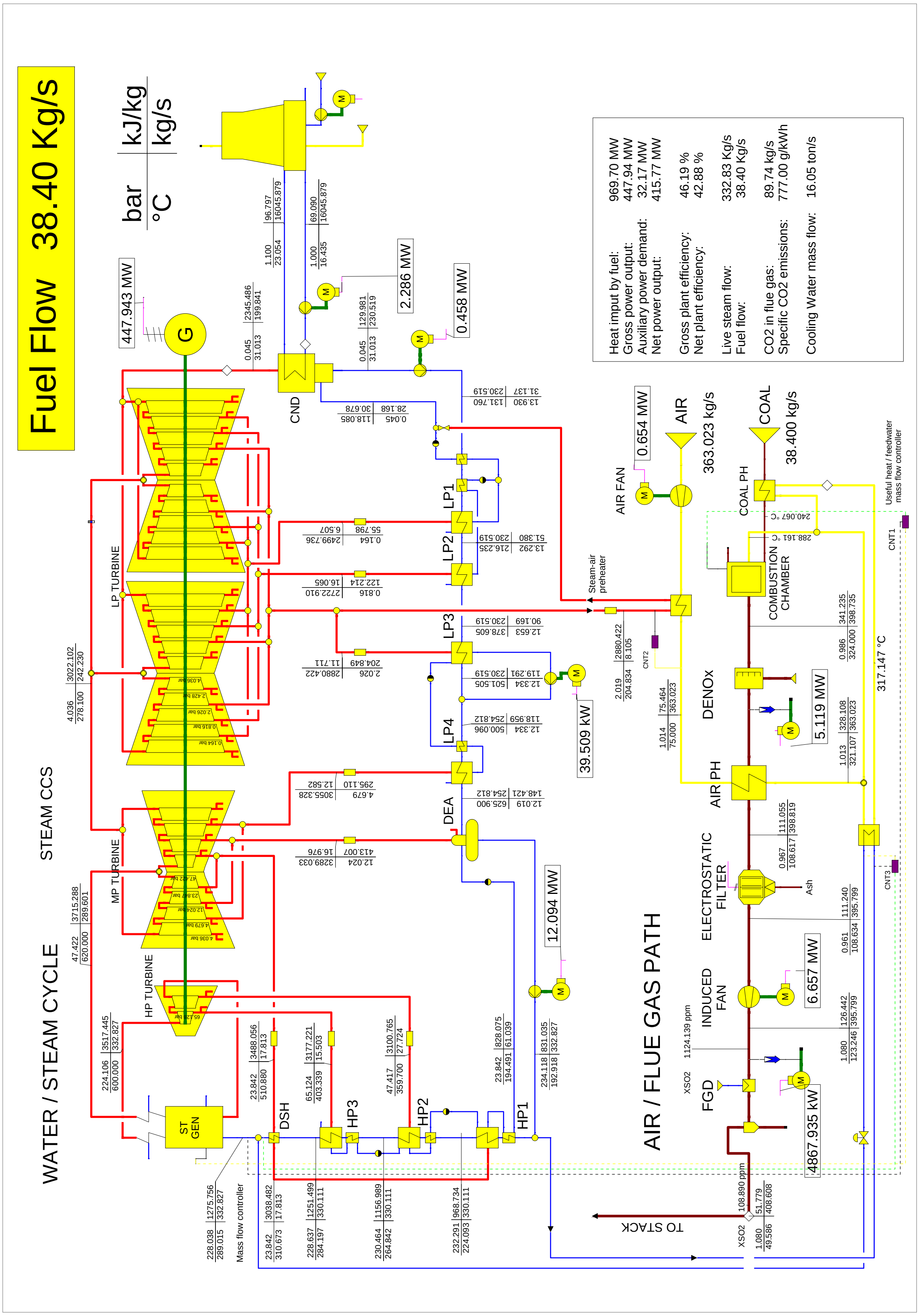

Figure 7.9: Complete RPP NRW model with EBSILON® Professional for partload: 80% of coal mass flow

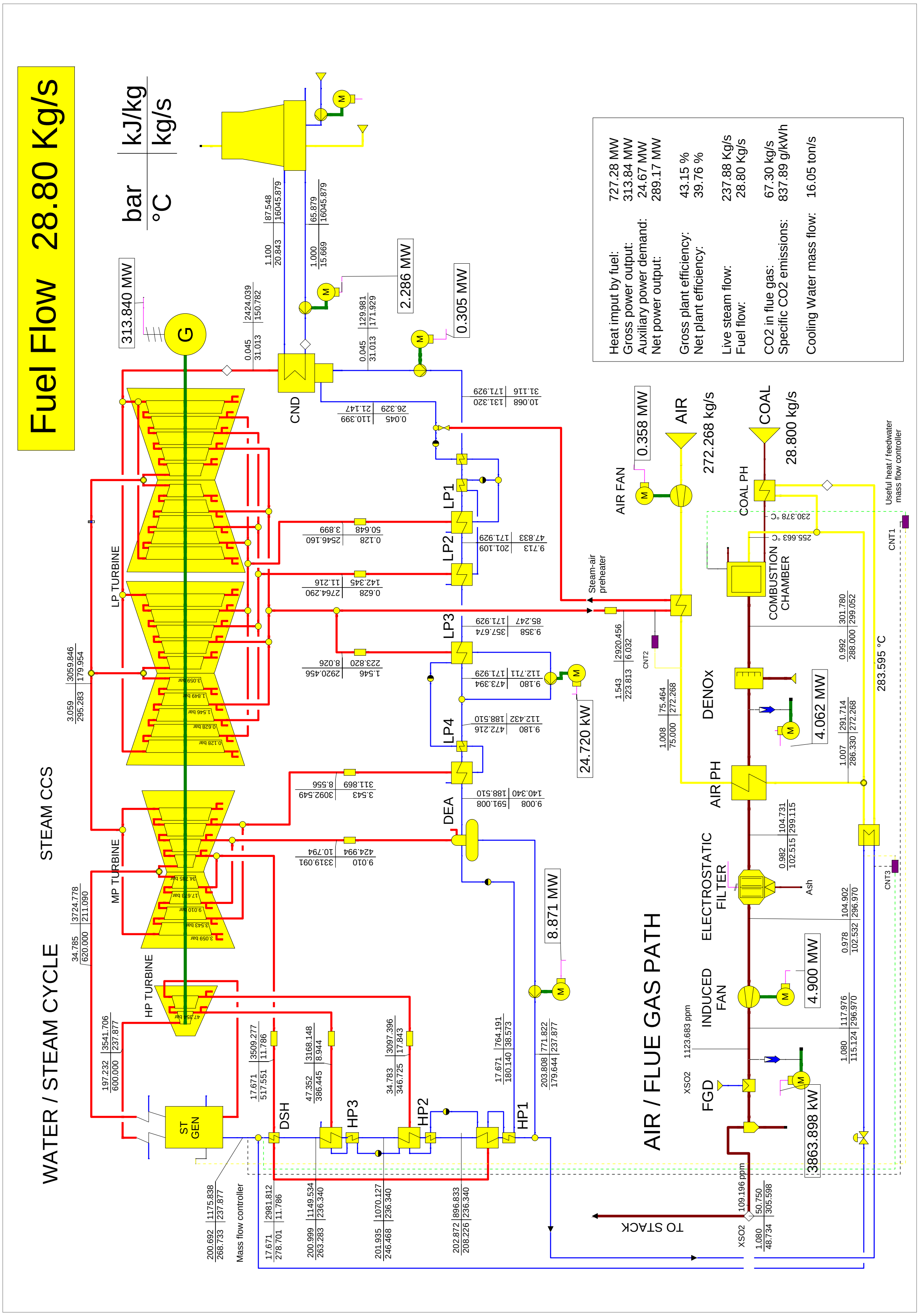

Figure 7.10: Complete RPP NRW model with EBSILON® Professional for partload: 60% of coal mass flow

8. Model and Simulation of the Steam Power Plant with Post-combustion Capture

Within this chapter, the capture plant will be modeled and once validated, will be retrofitted to the RPP NRW model created in chapter 7 for design case and partload performance analysis.

8.1. Capture Plant Model

The model of the Post-combustion capture plant will simulate operation of the basic process flow-sheet for MEA absorption displayed in figure 4.1. In section 4.1 the post-combustion capture plant was divided in the following sections: flue gas pre-treatment, CO_2 separation, solvent regeneration, and CO_2 compression.

Flue gas pre-treatment consists of an additional FGD plant, to reduce SO_x contents below 10 ppm. Section 4.1.1 summarizes main impurities to be reduced prior to the CO_2 separation. To balance pressure drop in the absorption column, an additional fan is added to the flue gas path. Subsequently flue gas is cooled down to 40°C. Figure 8.1 displays the model of the flue gas pre-treatment. Consumption of the additional FGD were obtained from [35]. Blower efficiencies, 85% isentropic and 99% mechanical, are EBSILON® default values.

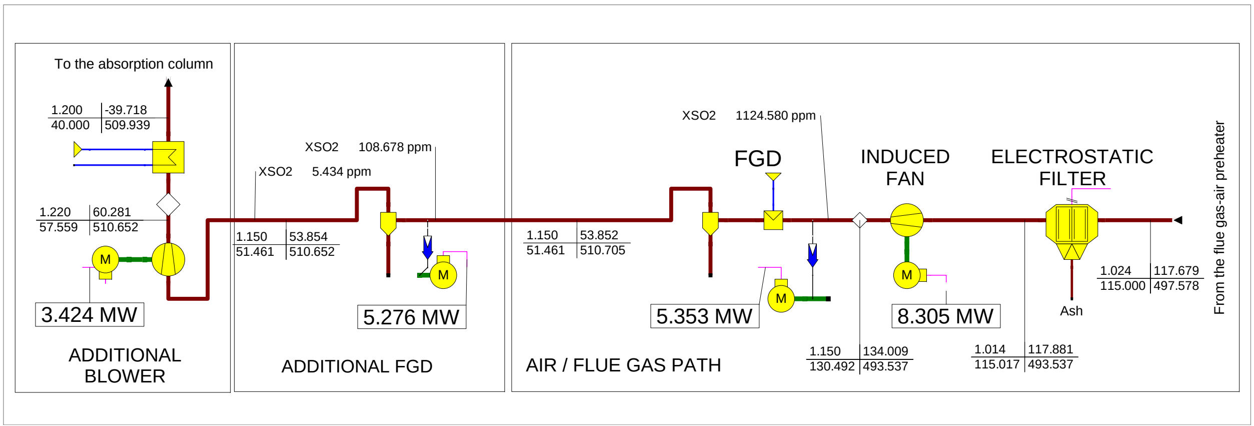

Figure 8.1: Model of the flue gas pre-treatment in the post-combustion capture plant

As already mentioned, the CO_2 separation and solvent regeneration process will be modeled as a black box. This will allow us to focus on the plant integration for an efficient operation of the retrofitted power plant rather than in an internal capture process optimization. Since there is no capture module within EBSILON® components is necessary to program it with an *EbsScript*.

With *EbsScript* programming is possible to use all calculation parameters in the model to program a new module that behaves equal to the CO_2 separation plant. Thus, by analyzing the basic MEA absorption process, all main input/output connections can be defined (see table 17). To control the performance of the capture plant is necessary to select certain parameters which directly affect the energy requirements and operation of the capture plant. Energy consumption and process operating conditions of the post-combustion capture technology were discussed in sections 4.2 and 4.3. In accordance with those sections we selected the following parameters for the CO_2-MEA chemical absorption (figure 8.2):

- **JCO2 (%)** The first parameter is the *CO_2 separation rate*. This factor will affect total thermal and electric energy consumption of the capture process.
- **Q4N (kJ/kgCO$_2$)** Electric power consumption of pumps and auxiliaries can be modeled with the parameter *specific electric consumption* per kg of flue gas treated. This value depends strongly on the process flowsheet and the solvent flow rate.
- **QSOLVN (kJ/kgCO$_2$)** To model the thermal energy requirements the most suitable parameter is the *specific heat demand for capture*. By selecting this parameter, we are taking into account solvent properties and the three main factors for solvent regeneration: desorption enthalpy, energy required for solvent heating and the energy consumption for stripping steam generation.
- **DP (bar)** Represent the pressure drop in the absorber. The absorber column pressure is relevant because increases reactivity between MEA and CO_2, reducing solvent flow and therefore the energy for solvent regeneration. In contrast, high pressure operation increase blower energy consumption. Since the blower demand increase is more significant, the absorber usually works near atmospheric conditions.

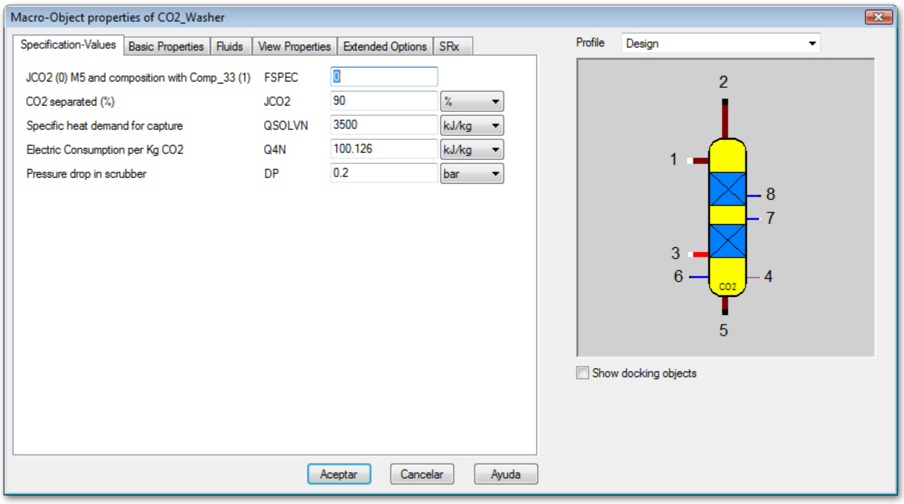

Figure 8.2: Properties window of the programmed EbsScript module for the post combustion capture

8.1.1. Boundary Conditions

More parameters could have been selected, achieving an exact model but adding complexity to the EbsScript programming. We considered this approach valid for our analysis as long as several boundary conditions are not exceeded. MEA solvent has to be heated up to 120°C in the desorber column in order to regenerate the solvent (see section 4.1.3). This heat addition takes place in the reboiler, by a steam extraction from the power plant. Considering a pinch of 10K in the reboiler, the steam conditions are limited to a saturation temperature of 130°C and the correspondent saturation pressure of 2,7 bar. We considered this limit for the simulation considering that a pinch of 10K fits properly with state-of-art heat exchanger technology[14]. The extracted steam will leave

[14]Other literature [35] set a more conservative limit at 140°C and 3,614 bar

the IP/LP crossover pipe (see figure 4.4) and will condensate in the reboiler returning to the water/steam cycle as saturated water.

The desorber column is pressurized up to 1,8 bar (see section 4.3.2), and so, the CO_2 stream output to the compressor will leave at 1,8 bar. The water condenser installed at the top of the desorber column cool down the exiting CO_2-water mixture to 40°C enabling the separation of water from the CO_2. To cool down the CO_2 and condense the water, cooling water enters at temperatures below 40°C and leave the cooler at temperatures below 110°C (considering again a pinch point of 10K for the heat transference). The clean flue gas, with almost no CO_2 is released to the atmosphere at a temperature of 40°C and atmospheric pressure. In real processes, clean gas stream leaves the absorption column above 40°C due to the exothermic character of the MEA-CO_2 absorption. Nevertheless, since this is a low quality waste heat it shows no significant potential for plant integration and is not considered in our model.

	Way	**Pressure bar**	**Temperature °C**
Fluegas stream	IN	1,1	40
Cleaned fluegas stream	OUT	1	40
Separated CO2 stream	OUT	1,8	40
Steam injection	IN	> 2,701	>130
Condensate outlet	OUT	No pressure drop	Saturated water
Cooling water to Stripper in	IN	variable	<30
Cooling water to Stripper out	OUT	No pressure drop	<110
Electric consumption kW/kg fluegas treated	IN	-	-

Table 17: Input/output lines and boundary conditions for the simplified capture process model

The complete code and diagram of the macro EbsScript for the capture plant model is specified in Appendix A. Due to the lack of information about solvent, absorber column and desorber column performances in partload, no charlines have been programmed for partload operation in the capture plant module. Energy requirements are directly proportional to the flue gas to treat, and therefore in partload operation the EbsScript behaves proportional to this mass flow. Figure 8.3 shows the capture module connected to the flue gas pre-treatment.

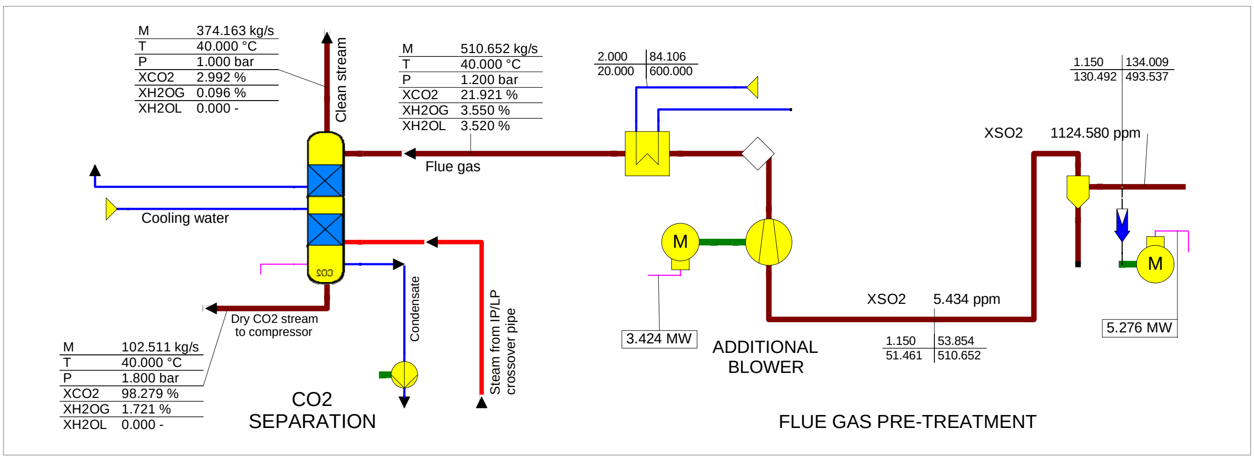

Figure 8.3: CO_2 Capture and flue gas pretreatment section for base load operation, 48kg/s coal massflow

8.1.2. Cooling Requirements of the Capture Plant

Four heat sources have to be cooled down in the capture plant by chilled water from the wet cooling tower: the CO_2 compressor cooling circuit, the CO_2-water cooler/condenser at the top of the desorber, the flue gas cooler and the lean solvent cooler. This last source shows no significant potential for heat integration and therefore is not considered within the capture plant EbsScript. Moreover, to a proper representation of this value, the whole chemical absorption process should be modeled. However, despite low temperatures achieved in the lean solvent cooling fluid make this source not interesting for heat integration, the amount of thermal energy that has to be evacuated is large, even higher than in the CO_2-water cooler/condenser. To reach realistic values for the cooling water requirements of the retrofitted power plant, lean solvent cooling water has to be approximated.

Simulations carried out by researchers of the Institute for Energy Systems and Thermodynamics of the Vienna University of Technology concluded that heat energy to be evacuated in the lean solvent cooler ($Q_{L,spec}$) is around 1,5 GJ/ton CO_2 captured. This parameter allows us to calculate an approximated value for the cooling water requirements in the lean solvent cooler. A simple energy balance in the heat exchanger gives us the cooling water mass flow:

$$\dot{Q}_{Lean} = Q_{L,spec} \cdot \dot{m}_{\mathrm{CO}_2} = Q_{L,spec} \cdot \dot{m}_{fluegas} \cdot X_{\mathrm{CO}_2} \cdot JCO2 \tag{8.1}$$

$$\dot{Q}_{Lean} = \dot{Q}_{cw} = \dot{m}_{cw} \cdot \Delta H_{cw} \tag{8.2}$$

Where $\dot{Q}_{cw}$ is the heat transferred to the cooling water, $\dot{m}_{cw}$ the required cooling water mass flow and ΔH_{cw} the enthalpy difference of the cooling water. Assuming a temperature increase of 8K in the cooling water, from 17°C to 25°C, the following equation calculates $\dot{m}_{cw}$:

$$\dot{m}_{cw} = \frac{\dot{Q}_{Lean}}{\Delta H_{cw}} = \frac{Q_{L,spec} \cdot \dot{m}_{fluegas} \cdot X_{\mathrm{CO}_2} \cdot JCO2}{h_{25} - h_{17}} \tag{8.3}$$

Table 18 shows the results of the calculation for the studied cases. Since $\dot{Q}_{Lean}$ is only a function of the separated CO_2, it is not afected by heat integration modifications and it will remain constant henceforth.

Study Case	Lean solvent cooler cooling water
Base load	4,52 ton/s
Partload 80%	3,61 ton/s
Partload 60%	2,74 ton/s

Table 18: Cooling water requirements for the lean solvent cooler within the capture plant

8.1.3. CO2 Compressor Model

Section 3.4 contains the features of CO_2 compression and state-of-art equipment. CO_2 is generally compressed over supercritical pressure up to 100 to 150 bars. For this study CO_2 pressure selected was 120 bar. From a first approach a simple 5 stages compressor with intercooling was modeled (see figure 8.4). Intercooling is required to minimize energy consumption of the next compression stage and also to dry the CO_2 stream by condensing gaseous water still present in the CO_2 flux.

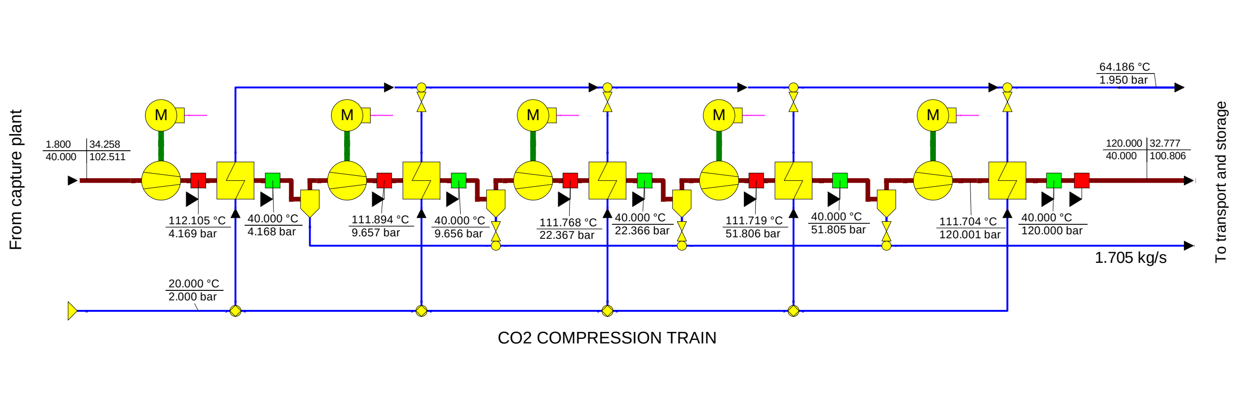

Figure 8.4: CO_2 Compression model for base load. Five stages compress CO_2 up to 120 bar for efficient transport

8.2. Baseload Simulation

With all sections of the capture plant modeled and operating, the reference power plant can be retrofitted with the post-combustion capture plant. Without integration between both plants, there is only two required connections: the steam extraction from the IP/LP crossover pipe and the return of its condensate to the LP feedwater heaters line. The condensate will be injected in front of the feedwater heater LP3, the optimal location for the capture parameters selected for the study. As we already mentioned, the steam extraction point and condensate return depend strongly on the characteristics and heat requirements of the capture process.

For this study the basic MEA process has been modeled. Key features of the capture and compression process are detailed in the table 19 below and will remain constant for base load and partload conditions.

	Unit	Values
CO_2 Capture rate	%	90
Specific heat for capture	GJ/ton CO_2	3,5
Specific electric consumption	GJ/ton CO_2	0,1
Reflux ratio in desorber	tonH_2O/tonCO_2	0,6
Pressure drop in the absorber	bar	0,1
Compression pressure	bar	120

Table 19: Selected parameters for the capture process model [24, 10, 35]

Figure 8.14 shows the reference power plant NRW retrofitted with the post-combustion. The CO_2 emissions reduction is substantial, from 726g/kWh to 97g/kWh. However, the efficiency drop increases around 34% the CO_2 generated in the power plant. Figure 8.5 corresponds exactly with the graphic 3.1 obtained from the Intergovernmental Panel on Climate Change [16].

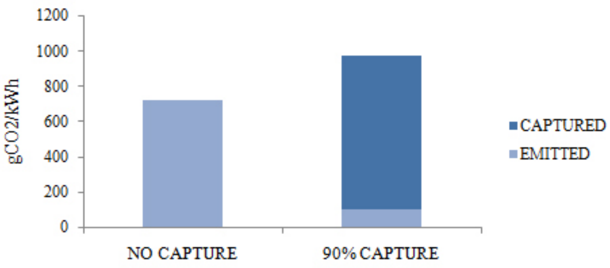

Figure 8.5: Increased CO2 production resulting from loss in overall efficiency in the RPP NRW

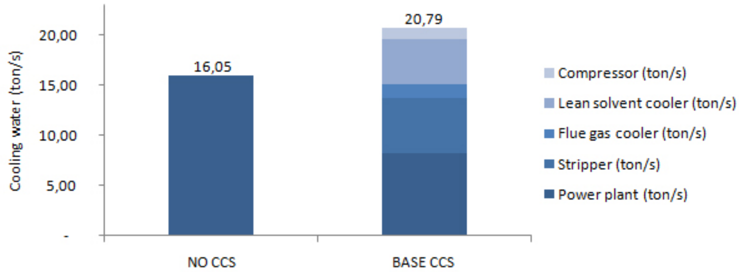

Figure 8.6: Cooling water requirements in base load operation for the RPP NRW with non integrated CO2 capture plant and the RPP NRW without capture

For baseload operation the steam extraction for the capture plant is 149,8 kg/s steam. Steam parameters are 5 bar and 268,3°C. This amount of steam represents almost 50% of the total steam directed to the LP turbine and causes a decrease in the gross power output up to 509,8 MW. Figure 8.14 displays the retrofitted reference power plant and details the main energy consumers from the capture plant and their effect over the overall plant efficiency. Net efficiency of the power plant drops from 45,9% to 34,3%, a decrease of 11,6% points. Net efficiency is more affected by the capture retrofitting than the gross efficiency due to the electric consumption of CO_2 compressor, pumps and auxiliaries of the separation plant, blower and additional FGD.

The drastic decrease in steam mass flow through the low pressure turbine almost halve the condenser duty that now requires 8,2 tons per second of chilled water from the wet cooling tower instead of 16,0 ton/s. However, the capture plant needs large amounts of cooling water to operate, around 12,5 ton/s, and therefore the cooling water requirements of the retrofitted power plant increase by almost 30% (see figure 8.6). The lean solvent cooler and CO_2-water cooler/condenser cooling water consumption together represent nearly 80% of the total requirements in the capture plant.

8.3. Partload Simulation

80% Partload For this partload case, 38,4 kg/s coal mass flow, steam conditions are supercritical and the sliding pressure operation mode reduce steam conditions at the inlet of the low pressure turbine to 277°C and 3,99 bar. Steam parameters are into the limits required for solvent regeneration and the mass flow extracted is 119,8 kg/s over 246,9 kg/s entering the IP/LP crossover pipe. This amount represents again values near 50% of the total mass flow. With regard to efficiency decrease, compared with 80% partload without capture there is a decrease of 11,3% points from 42,9% to 31,6% with 90% carbon capture.

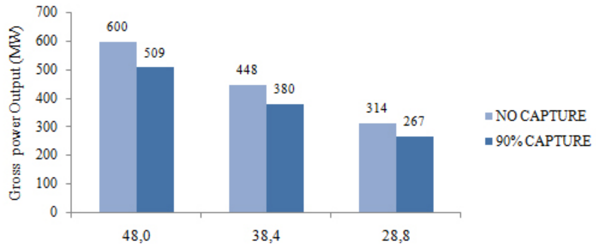

Figure 8.7: Gross Power output of the RPP NRW for the studied cases, without capture and with 90% capture

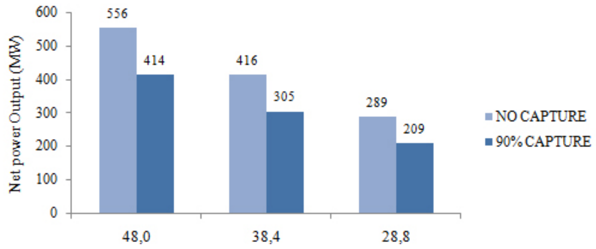

Figure 8.8: Net Power output of the RPP NRW for the studied cases, without capture and with 90% capture

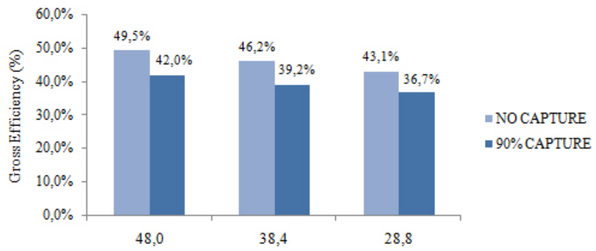

Figure 8.9: Gross Efficiency of the RPP NRW for the studied cases, without capture and with 90% capture

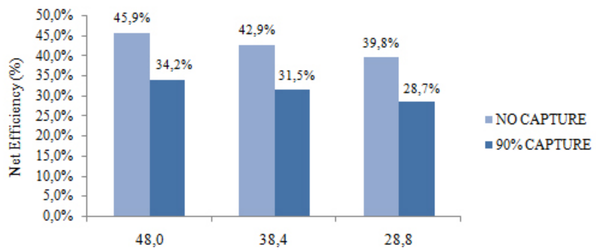

Figure 8.10: Net Efficiency of the RPP NRW for the studied cases, without capture and with 90% capture

60% Partload In this case, pressure of the steam line is reduced due to the sliding pressure operation mode to subcritical levels. The IP/LP crossover pipe operates at 292°C and 2,97 bar. Steam conditions are within the limits imposed for solvent regeneration. However, despite a steam pressure of 2,97 bar corresponding with a saturation temperature of approximately 133°C is enough temperature difference for MEA based solvents, this conditions could not be suitable to regenerate other class of solvents with higher reboiler temperature requirements. If that is the case, steam has to be extracted from other point of the cycle, or a throttle located in the IP/LP crossover pipe if the extraction remains there. Consequences of the second solution would be efficiency drop due to throttling losses. Net efficiency decrease for 60% partload is 10,9% points from 39,8% to 28,9% with 90% capture. In accordance with these results, efficiency penalty decreases sligthly in partload cases. However net efficiency penalty dependence with partload operation is not considered significant.

In sliding pressure operation mode the IP/LP crossover pipe steam pressure continues its decrease, and for 26,5 kg/s of coal mass flow steam conditions reach the pressure limit of 2,7 bar. This means that below 55% part load regarding to the coal mass flow, or 40% with regard to the gross power output, it would be necessary to install a throttle in the IP/LP cross over pipe in order to ensure enough pinch in the reboiler.

8.4. Capture Plant Energy Consumption

As mentioned in section 4.2, post-combustion capture technology requires large amounts of energy to operate. The result of the simulation corroborates this assertion showing penalty net efficiencies in design and off design cases around 12% points. A detailed analysis of those main energy consumers and establishment of potential improvements for each one will help the posterior optimization and process integration.

Capture plant energy requirements are both electric and thermal energy. To allow an appropriate analysis it is necessary to compare measures of energy in the same form. Such study, involving all heat flows between both plants, would lead to a convenient calculation of the steam extraction impact on the power plant electric output. Section 4.2.3 describes a simplificated method to obtain the power equivalent factor (PeF) which relates heat demand to power output drop. For this case, since the capture plant is not integrated, it is possible to calculate steam extraction impact in a simple way. Both plants are linked only by one steam extraction and its condensate return. The effects of this extraction on the steam/water cycle are a reduction in power output, and due to the reduced feedwater mass flow, a reduction in energy consumption of the condensate pump, cooling pump and third feedwater heater pump. Therefore, electric energy decrease will be the gross power output decrease minus the energy consumption decrease of those mentioned pumps (the rest of the cycle components behave equally). Figure 8.11 presents the relative energy consumption of the different components for the simulated post-combustion power plant.

Figure 8.12 shows how the relative thermal energy consumption slightly decreases in partload, going from 63% for design case to 57% for 28,8 kg/s partload. In contrast, relative consumption of the compressor increases from 24% to 28% for the 28,8 kg/s partload case. This analysis confirms that the two main energy consumption factors of a basic MEA post-combustion capture process are the solvent regeneration and the CO_2 compression, accounting both more than 85% of the total. Therefore, process improvement and compression research represent the principal challenges for post-combustion capture technology.

Integration and internal process improvement To reduce the heat demand of the capture plant it is essential to follow a double approach; improve the capture process, and high integration with the steam power plant. The first approach has briefly been discussed in section 4.6 and deals with the search for new solvents, improved less energy-intensive process configurations and optimal operation conditions. This approach is not longer considered in this thesis, but in order to show its potential a series of simulations have been calculated for different capture process scenarios. Thermal consumption of the capture plant can be briefly summarized by the specific heat demand. Figure 8.13 displays the impact of the capture plant on the net efficiency. Next generation of solvents (see section 4.6) with a specif demand near 2000 kJ/kg CO_2 could reduce penalty efficiency up to 8,4% points.

Simulation results are comparable to the values of power energy consumption in several literature sources consulted [25, 7, 35] and therefore, we consider validated the model, and suitable for further study on plant integration.

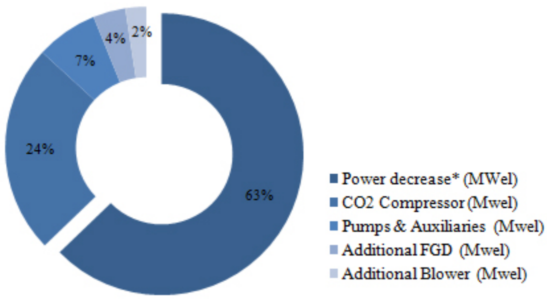

Figure 8.11: Relative energy consumptions for the different components of a standard MEA post-combustion process in design case (48kg/s coal mass flow). *Values for the electric power decrease due to the steam extraction in the IP/LP crossover pipe to feed the reboiler and regenerate the loaded solvent

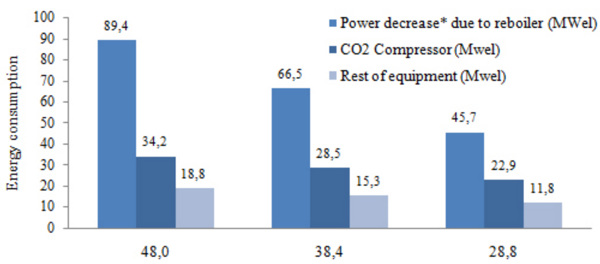

Figure 8.12: Energy consumptions for the different components of a standard MEA post-combustion process in design case (48kg/s) 80% partload (38,4kg/s) and 60% partload (28,8kg/s)

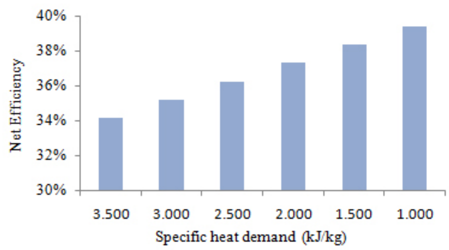

Figure 8.13: Net efficency of the RPP NRW for different specific heat demand, shows the important effect of solvent and processes improvements over the overall plant efficiency

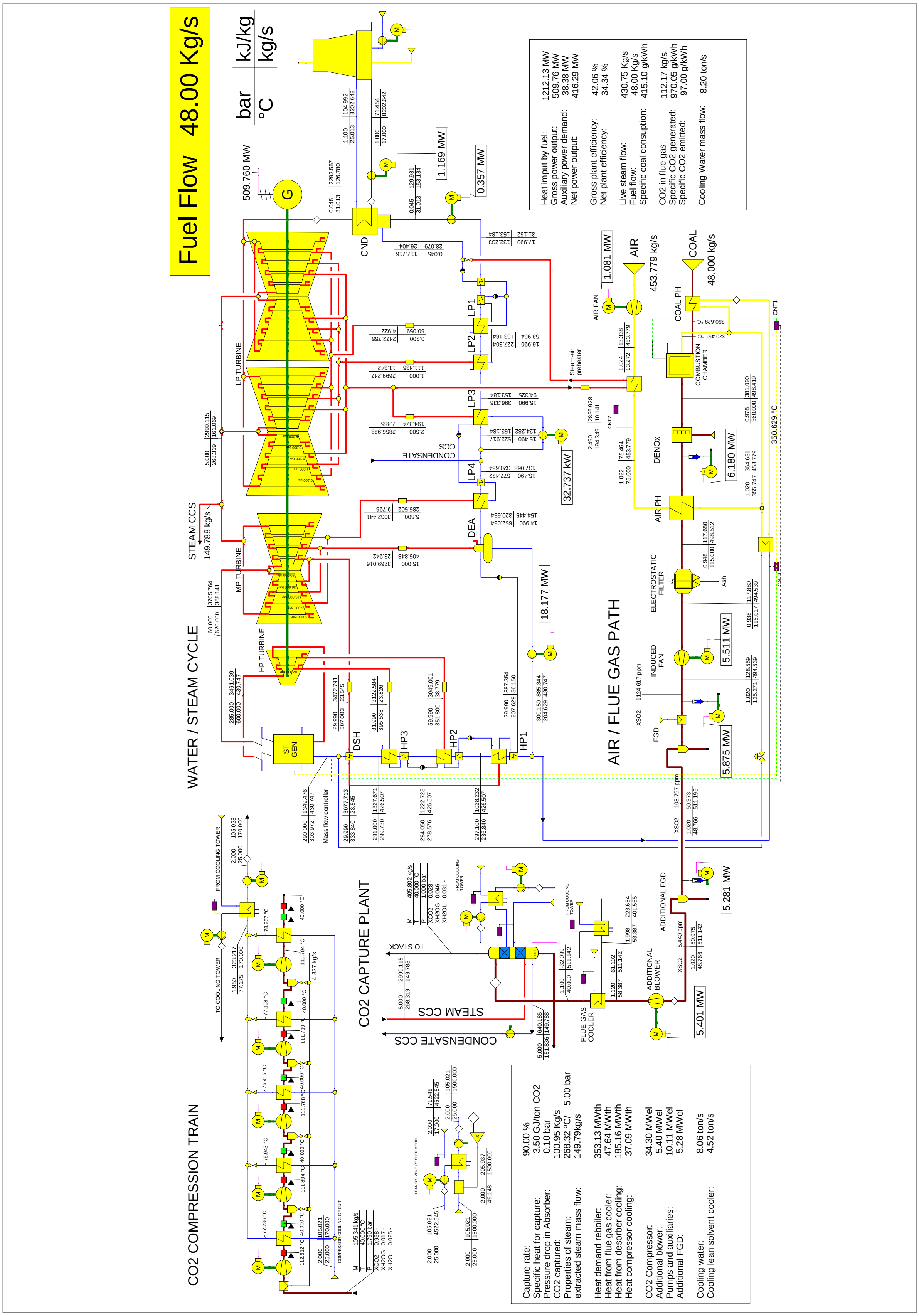

Figure 8.14: Complete RPP NRW model with post-combustion capture plant and CO_2 compression for design conditions: 48 kg/s coal mass flow.

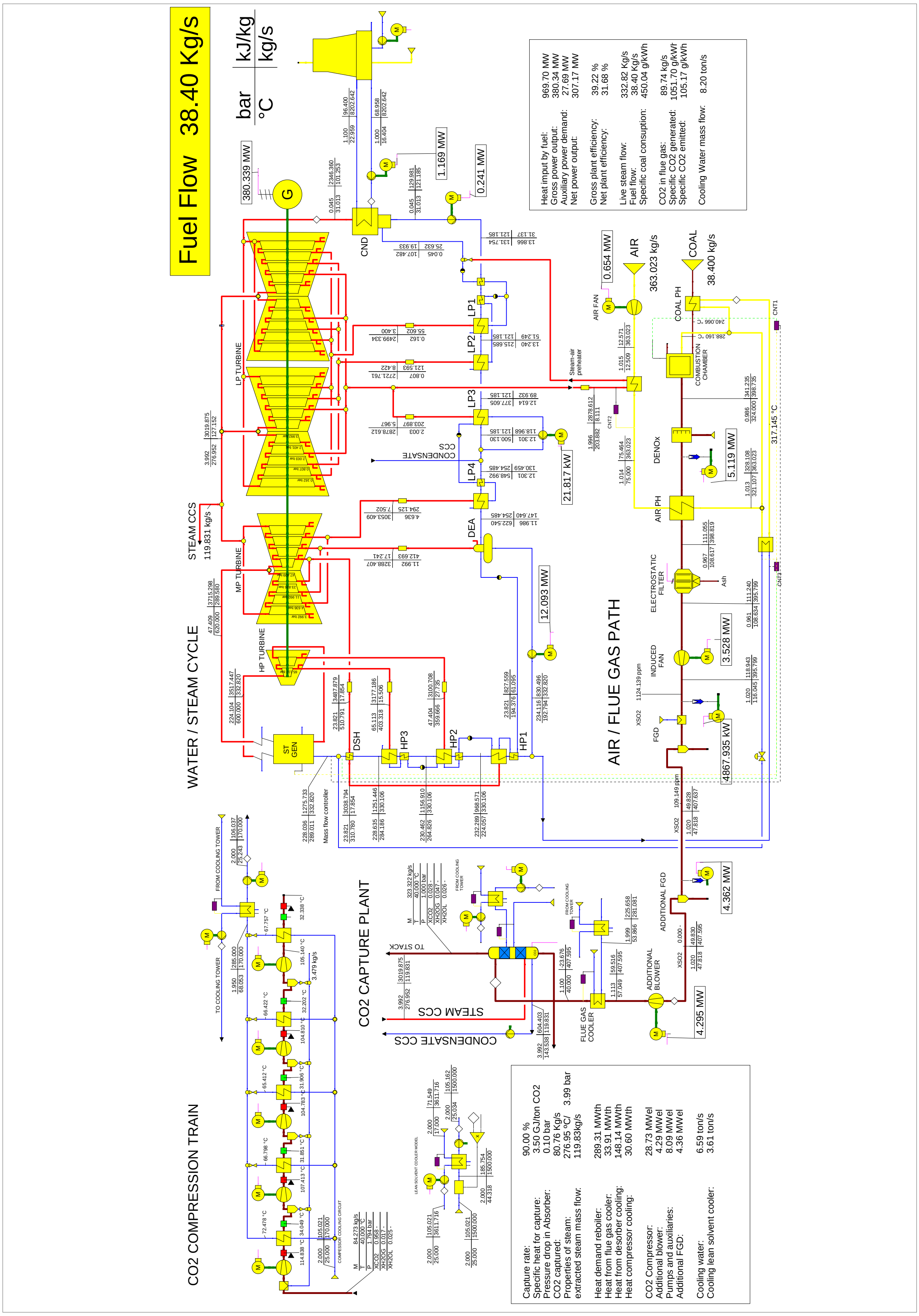

Figure 8.15: Complete RPP NRW model with post-combustion capture plant and CO_2 compression for 80% partload conditions: 38,4 kg/s coal mass flow.

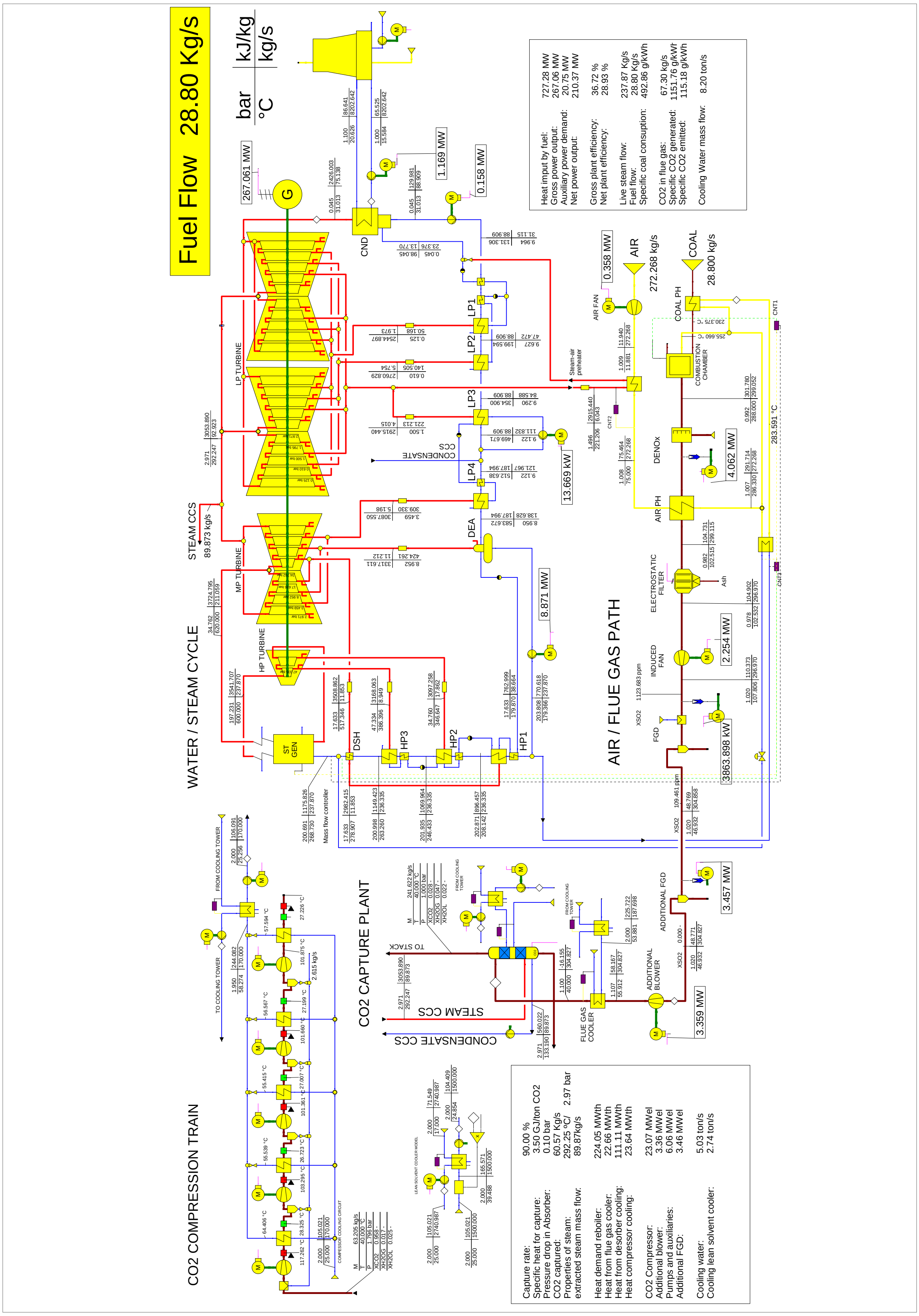

Figure 8.16: Complete RPP NRW model with post-combustion capture plant and CO_2 compression for 60% partload conditions: 28,8 kg/s coal mass flow.

9. Plant Integration Model and Simulation

In order to supply the large amounts of energy needs for solvent regeneration by the post-combustion capture plant, a steam extraction from the retrofitted power plant represents the most efficient way to provide required heat. The extracted steam feeds the reboiler and as a consequence there is a significant loss of power output. However, an important portion of the heat requirement of the capture process is still recoverable in the regenerator condenser where latent heat from the condensing stripping steam can be extracted. This heat and other relevant heat sources from the capture plant can be re-used to optimize power plant efficiency. Figure 9.1 displays a simplified overview of the main lines for heat integration and power consumption within a power plant with CO_2 capture.

From this point of view, the re-use of extracted heat in the water/steam cycle or air preheating circuit presents high potential to reduce overall efficiency penalty. Thus, a wide range of heat integration possibilities appear, always with strong dependence on the capture process and solvent properties. This chapter focuses on the integration possibilities within the retrofitted reference power plant NRW and provides a comparison study with the reference cases; RPP without capture (chapter 7) and non integrated post-combustion plant with MEA chemical absorption (chapter 8).

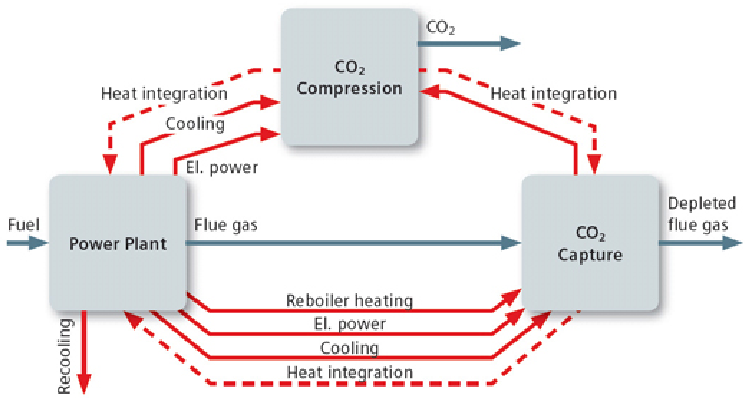

Figure 9.1: Energy flows between main sections of a power plant with CO_2 capture [21]

9.1. Heat Sources in the Capture Plant

Identify all heat sources and sinks within the capture plant is essential to enable a complete study of plant integration. The main heat flows, already mentioned in section 8.1.1 are the heat demand for solvent regeneration in the reboiler and cooling requirements in the following sections of the capture plant:

- **Stripping steam condenser:** cooling requirements in the stripping steam condenser at the top of the desorber represent a significant heat source in the capture plant. This component has as its main function to cool down the mixture CO_2-water ascending through the reboiler. Prior to the compressor, the CO_2 has to be separated from the stripping steam to reach the high purity required for transportation and storage. Thus, the mixture is cooled down to 40°C. As a secondary effect, reducing CO_2 temperature results in less consumption by the first stage of the compressor. For an appropriate model of this source it is necessary to calculate heat delivered by the stripping steam condensation and subsequent subcooling up to 40°C and the heat transferred by the cooling of the CO_2 stream from 120 to 40°C. Since the capture plant has been modeled as a *"black box"* it is not possible to precisely calculate the steam mass flow condensing at the top of the stripper. Nevertheless, an accurate estimation can be modeled based on the *reflux ratio*, the relation between the condensate returning from the condenser to the desorber and the amount of separated CO_2. Several literature sources [10, 24], analyze the basic MEA absorption process and conclude than the state-of-art reflux ratio is around 0,6 tones of condensed steam per ton of CO_2. By the use of this value and knowing the CO_2 mass flow from the simulation it is possible to find a close approximation to the transferred heat in the condenser. The implementation of this aspects within the "CO_2 Washer" *EbsScript* are detailed in Appendix A.

- **Lean solvent cooler:** cooling requirements to reduce lean solvent temperature to near 40°C before entering the absorber are also significant. However, this heat source is not considered to offer large potential for integration since the lean solvent comes from the crossed heat exchanger where it has already transferred a large amount of heat to the rich solution (see figure 4.1). Hot fluid temperature in the cooler is slightly higher than 40-45°C and shows low potential for integration. Heat extracted from the lean solvent cooler is not considered for heat integration but its value has been approximated to allow a realistic study of cooling water requirements (see section 8.1.2).

- **CO_2 compressor cooling circuit:** When compressing CO_2 with compression ratios of 2,3:1 for the modeled five stages simple compressor ,the CO_2 flux reaches temperatures above 110°C and therefore cooling fluid can be heated up to temperatures that enable integration with the low pressure feedwater line or the air preheating system. The potential of this source becomes even more important when a shockwave compressor is used. This technology (see section 3.4) consents compression ratios of 10+:1 and temperatures up to 255-265°C after each stage. This heat source has been modeled and represents, together with the stripping steam condenser, the two main heat flows suitable for plant integration.

- **Pretreated flue gas cooler:** after the additional FGD flue gas reaches temperatures around 50-60°C, as already mentioned in section 4.1.1, flue gas is cooled down to enter the absorber at optimal temperatures for the chemical absorption reaction, around 40°C. Thus, the flue gas cooler extract low quality heat, even when the extracted amount of heat is comparable with the quantity extracted by compressor cooling circuit. This heat is usually evacuated via cooling tower. Flue gas cooler is modeled and displayed in figure 8.1.

- **Waste heat on cleaned flue gas:** Last heat source is contained by the cleaned flue gas leaving the absorber. As mentioned before, heat in the cleaned flue gas is also low quality heat and does not show possibilities for integration. Besides, cleaned flue gas density has to be below ambient conditions to rise into the atmosphere.

9.2. Potential Integration Points in the Steam Power Plant

All heat sources presented above contain large amounts of heat at temperatures up to 110°C. Therefore, heat integration is limited to feedwater and feed air lines at temperatures below 100-105°C (for a pinch point of 5-10 K). In the water/steam cycle, the design pressure at the deaerator sets the maximal temperature that is possible to achieve in the low pressure feedwater heater line. For the reference power plant NRW this temperature is 198°C. Steam bleeds for the LP1 and LP2 heaters have saturation temperatures of 58°C and 99°C respectively. In LP3 condensation of the extracted steam takes place at 120°C. Thus, heat from the post combustion capture plant could only be transferred to the low pressure feedwater line, more precisely before the third feedwater heater.

The flue gas presents an opportunity to "upgrade" the heat from the capture plant. Currently the flue gas leaves the economizer at 360°C (in base load) and is used to preheat combustion air.

After the steam-air heater, feed air temperature is around 70°C and is subsequently increased up to 350°C in the flue gas-air preheater. Flue gas is cooled down to no less than 115°C; lower temperatures increase the risk of corrosion by condensation of the water and sulphur mixture present in the stream. Air could be therefore preheated up to 100-105°C by the waste heat from the capture plant and hence part of the flue gas heat, at higher temperatures, could be applied to the HP feedwater heater line.

9.3. Integration I: Air Pre-heating with Waste Heat

The first integration improves the performance of the flue gas path. As a previous step, operation of the additional blower is analyzed. The basic capture process locates the flue gas cooler after the blower (see figure 8.3). By switching the position of both components the blower consumption will decrease due to the lower temperatures of the flue gas. To avoid damages in the blower a drain is installed and all liquid water is extracted from the flue gas. As a secondary effect, water extraction increases CO_2 concentration and reduces the flue gas mass flow, improving the performance of the capture plant.

For base load operation, the 185 MW that have to be evacuated from the stripping steam condenser would require without integration 5,5 tons per second of cooling water. Waste heat can easily be transferred to the feed air and then, the flue gas heat excedent bypassed to the high pressure feedwater heater line (see figure 9.6). A stream of 618 kg/s water at 95°C heats up the air to 90°C, and the bypass transfers energy to the HP line by heating up water to the same temperature at the entrance of the boiler, 303,9°C. Bypass operation is controlled by "CNT1", wich calculates the exact water massflow to reach the scheduled temperature. The results of the simulation, displayed in table 20, show an increase in the net efficiency of 0,57% points, and an increase in net power output of almost 7 MW. This improvement represents a reduction in the net penalty efficiency of 4,9%.

	Unit	**Base CCS**	**Integration I**	**Variation**
Gross power output	MW	509,76	516,47	+ 6,71
Net power output	MW	416,29	423,21	+ 6,93
Gross efficiency	%	42,06	42,61	+ 0,57
Net efficiency	%	34,34	34,91	+ 0,55

Table 20: Results of the simulation for the first heat integration. Design case, 48 kg/s coal mass flow

Capture plant behavior Figure 9.4 shows the relative energy consumption of the capture plant, compared in electrical energy. Power equivalent factor (PeF) of the reboiler has been calculated by taking into account the power output drop and all variations in energy consumption of the water/steam cycle (see section 4.2.3). The obtained PeF drops to 0,22 MW_{el}/MW_{th} compared to 0,24 MW_{el}/MW_{th} for the retrofitted power plant without capture, an improvement of more than 8%. The blue circle represents the relative consumption of the components of the capture plant after the first integration, while in grey is displayed the base case relative consumption, without integration. We see how heat integration has an impact over the power equivalent factor, the heat requirement for the reboiler. The more integrated are both plants, the lower is the relative consumption of the reboiler.

Figure 9.5 shows the positive impact of switching positions of blower and flue gas cooler over the electrical consumption of the capture equipment a reduction in 0,5 MW_{el}.

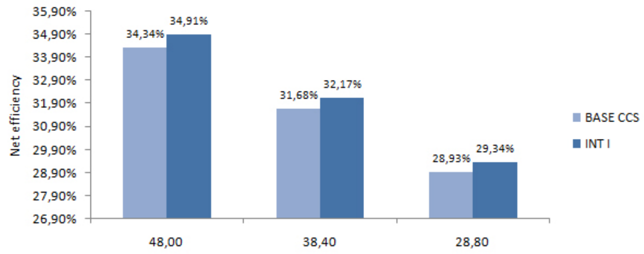

Figure 9.2: Net efficiency improvement after the first heat integration for study cases

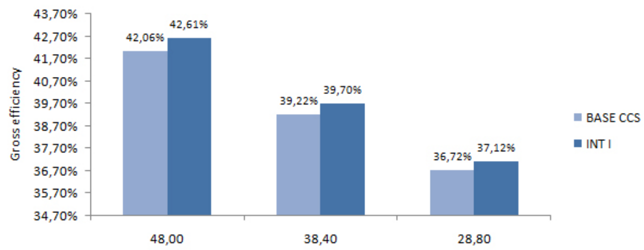

Figure 9.3: Gross efficiency improvement after the first heat integration for study cases

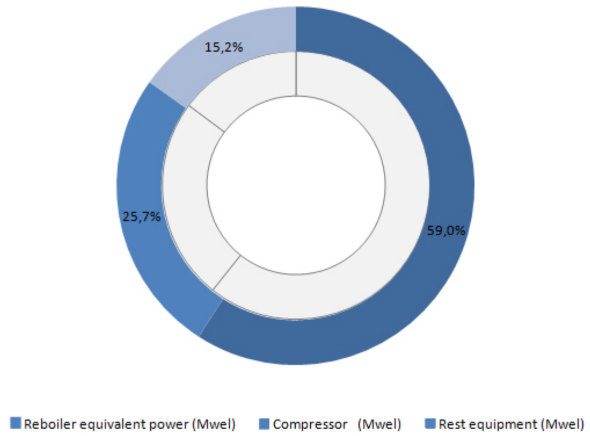

Figure 9.4: Relative equivalent electric energy consumptions for components of the capture plant (INT I) in design case, 48kg/s coal mass flow

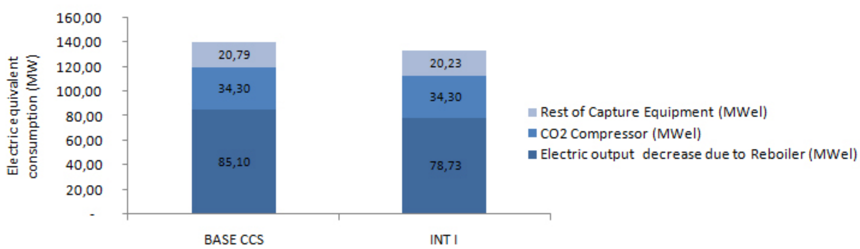

Figure 9.5: Absolute equivalent electric energy consumptions for components of the capture plant (INT I) in design case, 48kg/s coal mass flow

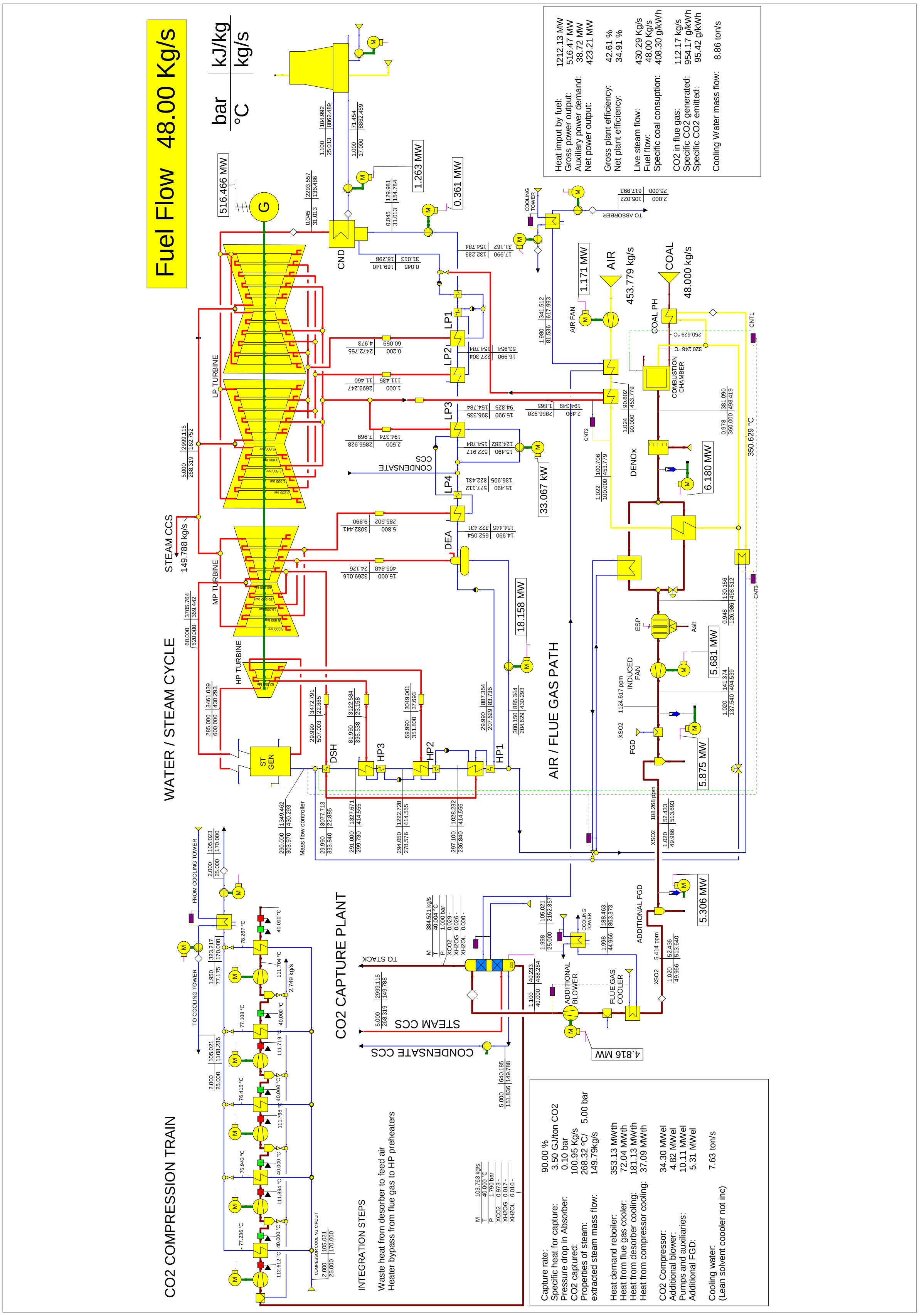

Figure 9.6: Complete model of the RPP NRW with integrated post-combustion capture plant (integration I) for design conditions, 48 kg/s coal mass flow.

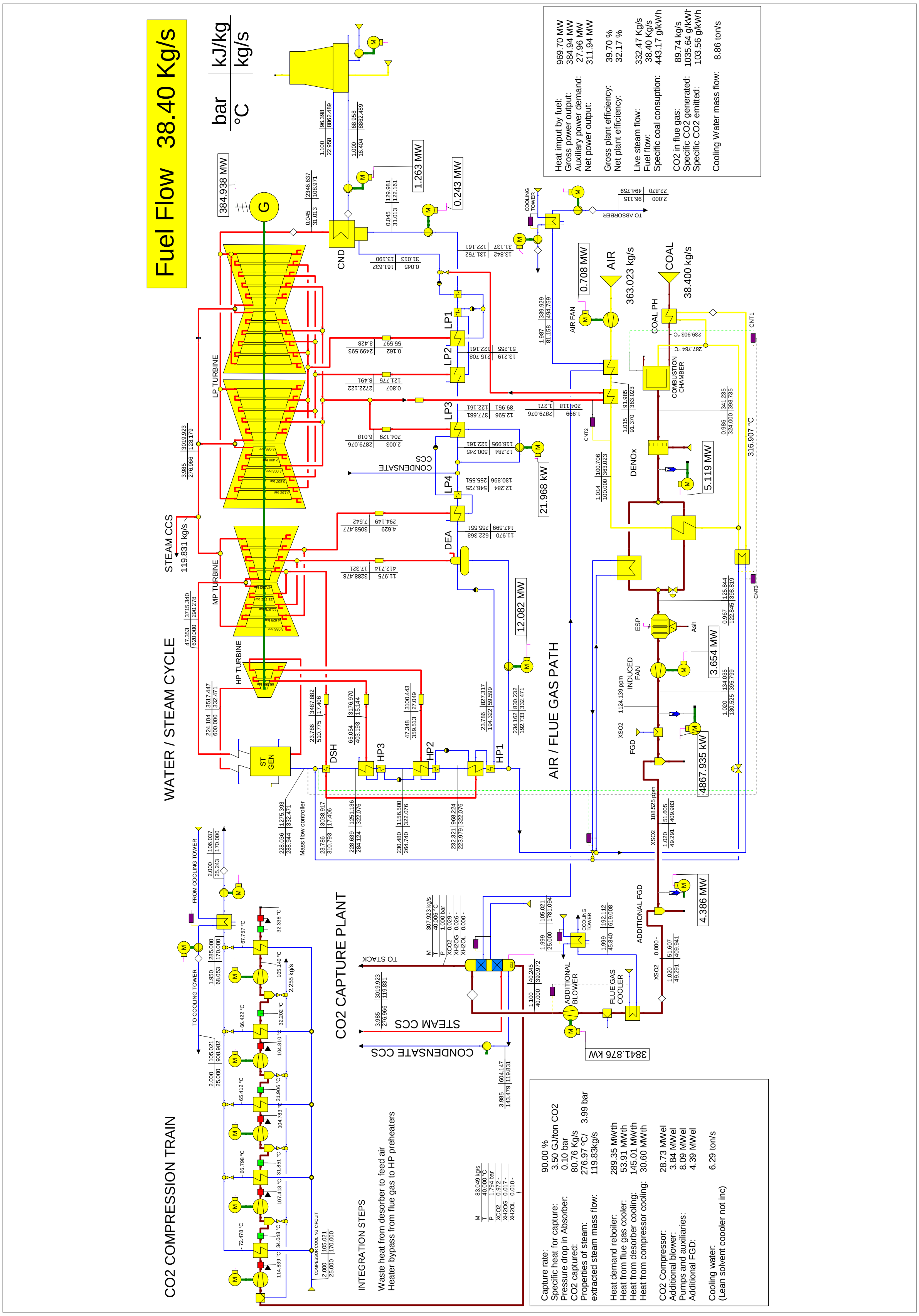

Figure 9.7: Complete model of the RPP NRW with integrated post-combustion capture plant (integration I) for 80% partload conditions, 38,4 kg/s coal mass flow.

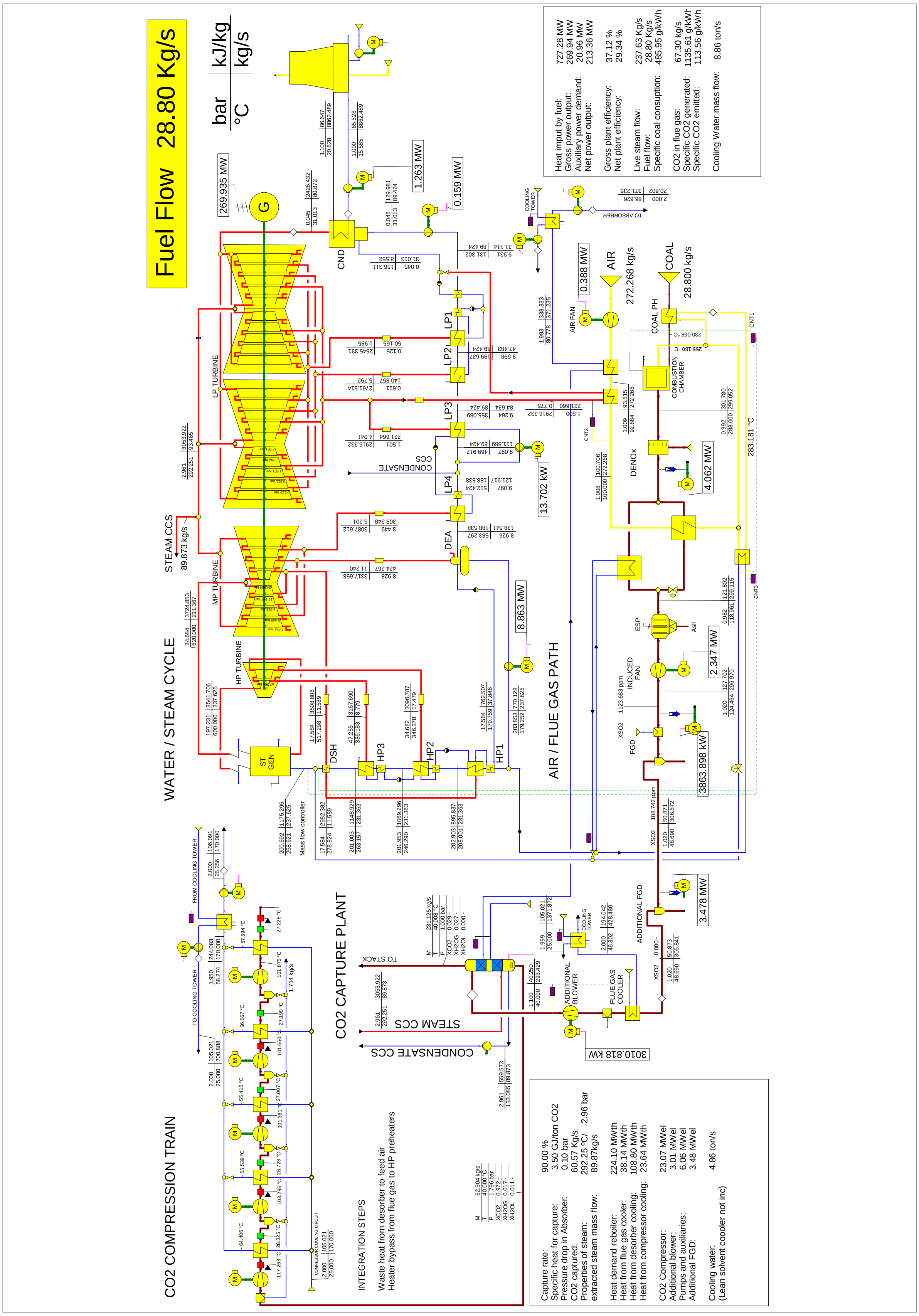

Figure 9.8: Complete model of the RPP NRW with integrated post-combustion capture plant (integration I) for 60% partload conditions, 28,8 kg/s coal mass flow.

9.4. Integration II: Waste Heat to LP Feedwater Line

The large amount of heat from the condensation of the stripping steam is not only enough to preheat the feed air but also the low pressure feedwater line to reduce the steam extractions driving LP1 to LP4. Water leaves the air-water pre-heater at 91°C, this temperature enables to transfer heat before the second preheater, LP2 heats up the water to 94°C and is still usefull. This second integration substitutes the first feedwater heater, LP1, for a water-water heat exchanger to transfer the heat from the capture plant. In the real case, this substitution could present complications since LP1 and LP2 are one unique component, a duplex heat exchanger (see section 2.2.3), besides it is usually inserted into the condenser neck. Nevertheless, for an appropriate study of heat integration between both plants, LP1 and LP2 are treated as independent heaters.

At this moment another heat source from the capture plant can be used to improve overall efficiency. The five stages CO_2 compressor is intercooled and evacuates 37 MW at 77°C that could be applied to preheat air and increase the available heat of the desorber cooling water to increase the transferred heat to the steam/water cycle. The simulation shows again a sensible improvement of 0,36% points on net efficiency and an increase in net power output of 4,4MW what results in an acumulated reduction of the net efficiency penalty of 8,1%points. Table 21 shows key data for this second integration step.

	Unit	Base CCS	Integration II	Variation
Gross power output	MW	509,76	521,09	+ 11,33
Net power output	MW	416,29	427,64	+ 11,35
Gross efficiency	%	42,06	42,99	+ 0,94
Net efficiency	%	34,34	35,28	+ 0,93

Table 21: Results of the simulation for the second heat integration. Design case, 48 kg/s coal mass flow

Capture plant behavior When the waste heat from the CO_2 compressor is transferred to the power plant, the relative power consumption of the reboiler continues its decrease, while the rest of the components performance stay constant. Figure 9.9 compares the relative consumptions of previous integration stages and reference case with this last integration. All heat integration steps basically transfer heat to the feedwater line in the water/steam to minimize steam extractions to the preheaters and therefore, increase power output. Efficiency increase results in an increase of cooling water of the power plant condenser, from 8,2 tons per second without heat integration to 9,78 ton/s after the second integration. In contrast, a high integrated capture plant requires less cooling water to operate since large amounts of heat are transferred to the water/steam cycle. Cooling water requirements of both plants are balanced and the total amount of cooling water remains almost constant (see figure 9.11).

Partload simulation Steam pressures and temperatures in sliding pressure operation mode do not show variation from the simulation of the reference power plant without capture. Pressures at the inlet of turbines decrease to reach optimal operations for part load. Pressure drop in partload conditions also affects steam extractions decreasing operation temperatures of the feedwater heaters. For this reason in the 60% partload simulation, steam extraction for LP2 has lower saturation temperature than the waste heat from the desorber, thus the steam mass flow to the LP2 is zero; second feedwater heater is not necessary. EBSILON® displays one warning, but the calculations are consistent.

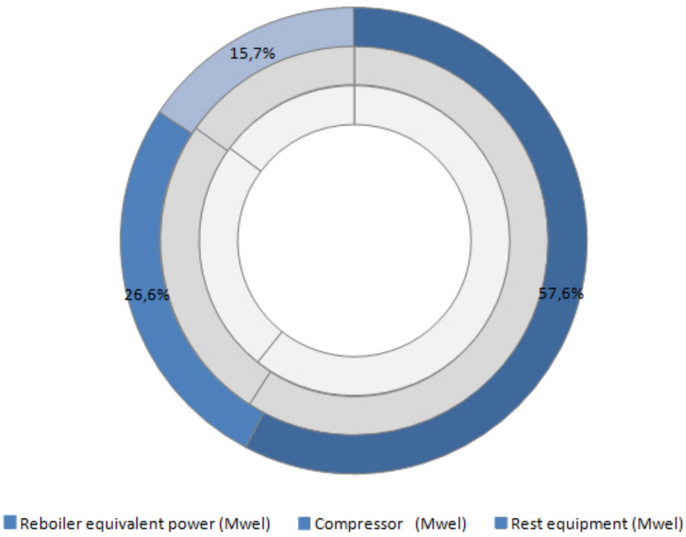

Figure 9.9: Relative energy consumptions for the different components of the integrated capture plant (INT II) in design case, 48kg/s. The inner circles represent values for the base CCS case and previous integration steps

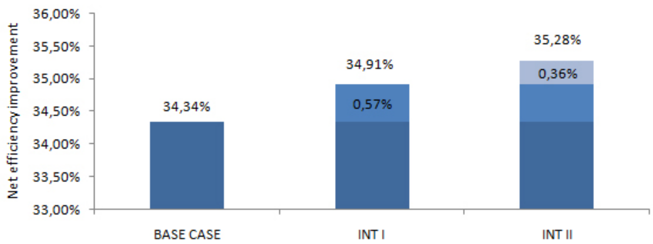

Figure 9.10: Net efficiency increase for the design case after heat integrations I and II

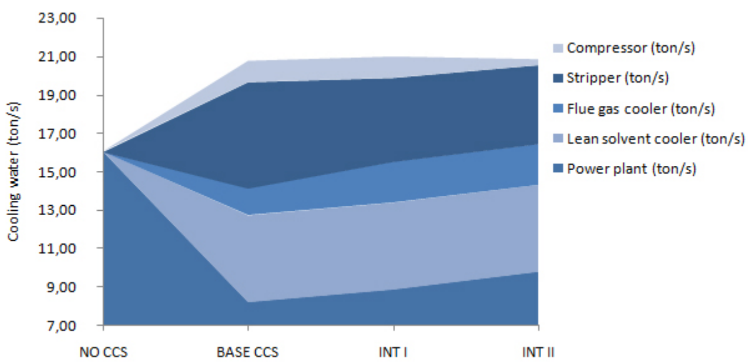

Figure 9.11: Cooling water requirements (ton/s) for the different components of the retrofitted power plant NRW after second heat integration for design conditions

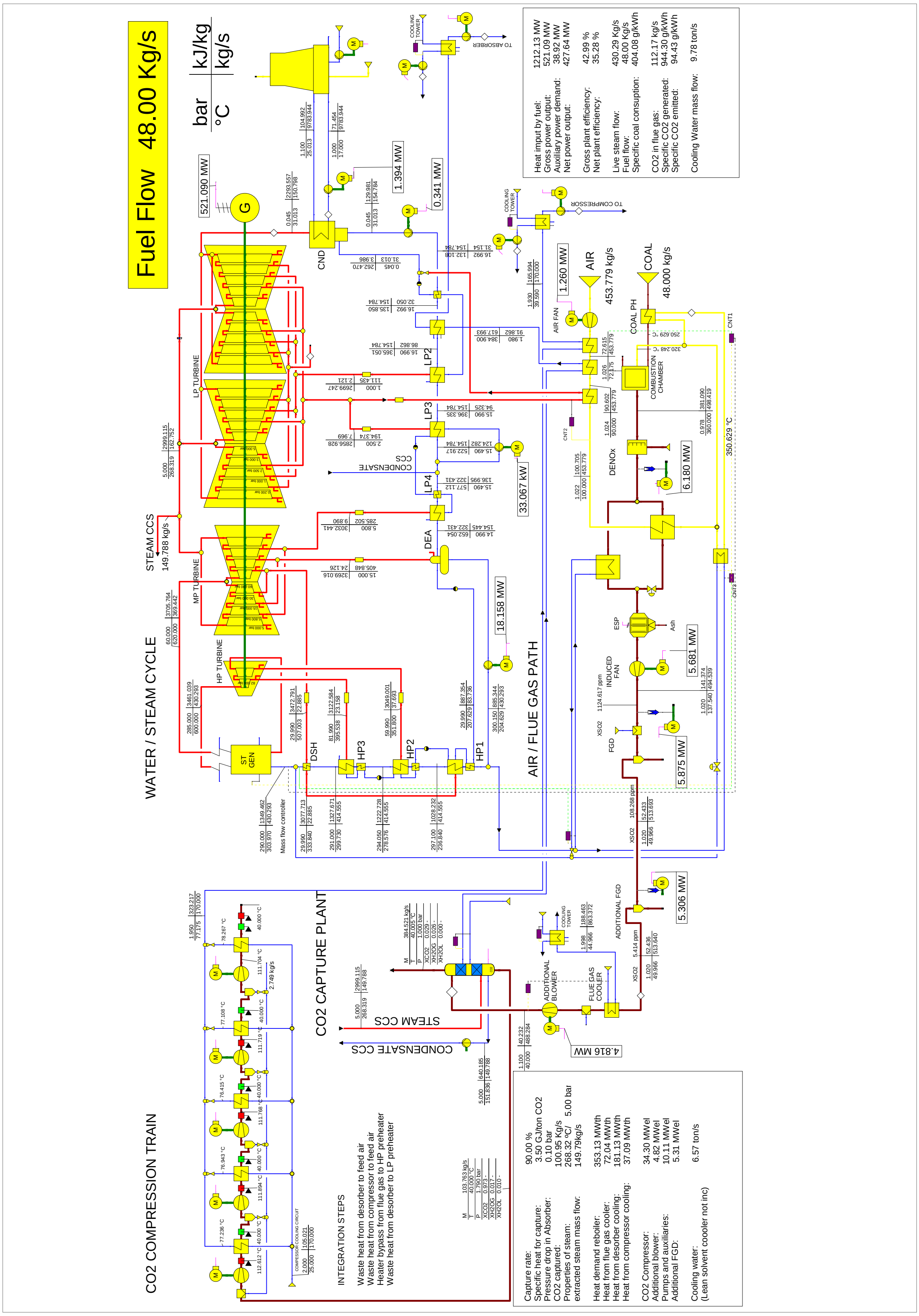

Figure 9.12: Complete model of the RPP NRW with integrated post-combustion capture plant (integration II) for design conditions, 48 kg/s coal mass flow

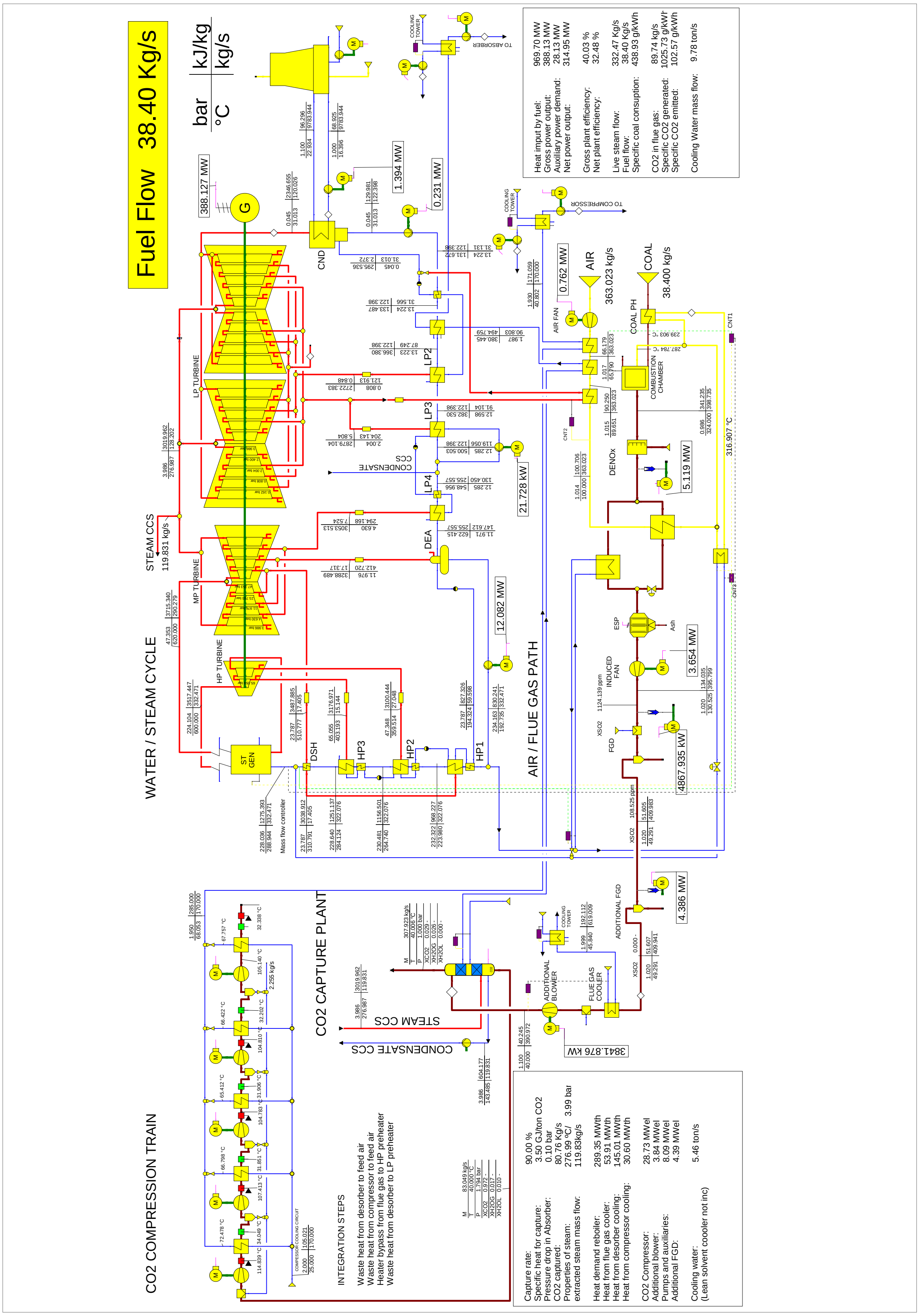

Figure 9.13: Complete model of the RPP NRW with integrated post-combustion capture plant (integration II) for 80% partload conditions, 34,8 kg/s coal mass flow

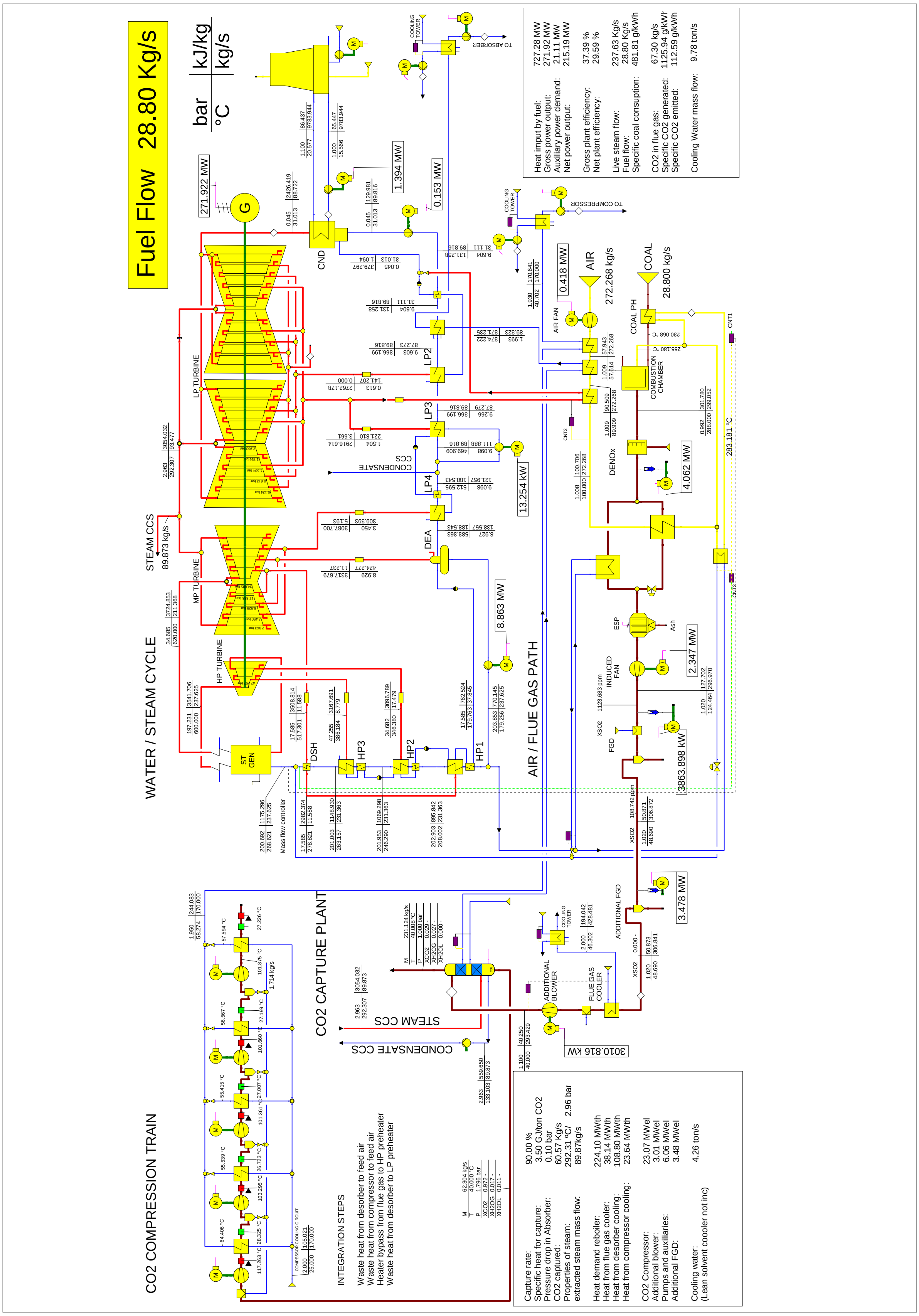

Figure 9.14: Complete model of the RPP NRW with integrated post-combustion capture plant (integration II) for 60% partload conditions, 28,8 kg/s coal mass flow

9.5. Integration III: Flue gas to LP Line

The heat bypass simulated for the first integration has positive effects over the efficiency of the power plant, however, because the water is entering the bypass at 203°C (temperature after the main feedwater pump) the flue gas can only be cooled down to temperatures around 215°C while it could be cooled down to 115°C. This situation represents an inefficiency for the cycle and besides, flue gas has to be cooled before entering the capture plant to 40°C, so it also increases the cooling water requirements of the flue gas cooler as figure 9.11 shows.

Next heat integration is directed to eliminate such inefficiency by the installation of a flue gas low pressure feedwater preheater. Water is extracted after the waste heat recovery heat exchanger substituting LP1 at 97°C and directed to a flue gas-water heat exchanger located downstream the bypass where the flue gas can now be cooled down to 115°C and feedwater heated up to be injected again just before the deaerator. Optimal extraction mass flow is 5 kg/s with the extracted water temperature rising to 198°C. The fact that low mass flows and high temperature increases are more efficient for this case can be understood by the reduction in steam bled to the deaerator that this water injection causes.

One additional improvement is implemented at the same time; the increase of desorber cooling water temperature up to 110°C, limit value that still fulfills design conditions in the condenser (pinch point of 10K). Water enters the condenser at 25°C and reaches 110°C in the counter current condenser while CO_2 and stripping steam enter at 120°C and leave at 40°C. To avoid boiling within the cold side, water must be pressurized. For the simulation a pressure of 2 bar was selected.

	Unit	**Base CCS**	**Integration III**	**Variation**
Gross power output	MW	509,76	527,21	+ 17,45
Net power output	MW	416,29	432,46	+ 16,18
Gross efficiency	%	42,06	43,49	+ 1,44
Net efficiency	%	34,34	35,68	+ 1,33

Table 22: Results of the simulation for the third heat integration. Design case, 48 kg/s coal mass flow

Main results of the simulation are presented in table 22. With a net efficiency improvement of almost 0,4% points, the third heat integration increases net power output to 16,18 MW over the reference case. Efficiency penalty is reduced by 11,5%. From this point, gross efficiency improvement starts to be more significant than net efficiency due to the growing importance of the auxiliary consumption.

Capture plant behavior As we noted before, heat integration reduces impact of the heat energy demand in the reboiler. After the third integration the relative equivalent consumption for solvent regeneration has been reduced more than 10%. Partload operation reduces even more relative power consumption of the reboiler (see figure 9.16).

Total cooling water requirements decrease slightly despite the increase in the power plant from 8,9 ton/s to 9,8 ton/s. The reason can be found in the reduction of compressor and stripper cooling water requirements (see figure9.18). However, The cooling system has to provide almost 30% of extra water for the capture plant.

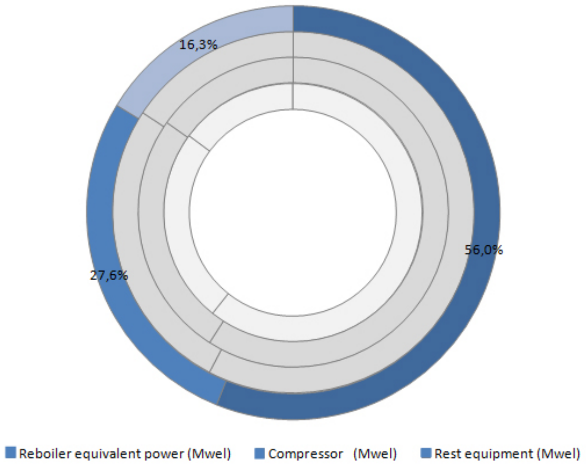

Figure 9.15: Relative energy consumptions for the different components of the integrated capture plant (INT III) in design case, 48kg/s.

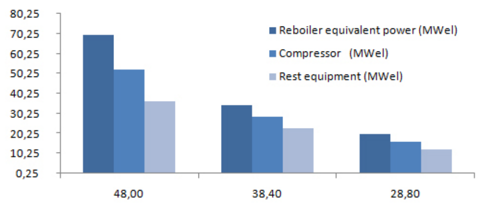

Figure 9.16: Capture plant equivalent power consumptions for base load, 80% and 60% cases

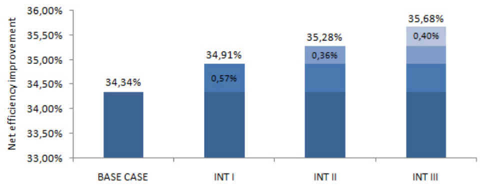

Figure 9.17: Net efficiency increase for the design case, 48 kg/s after heat integrations I, II and III

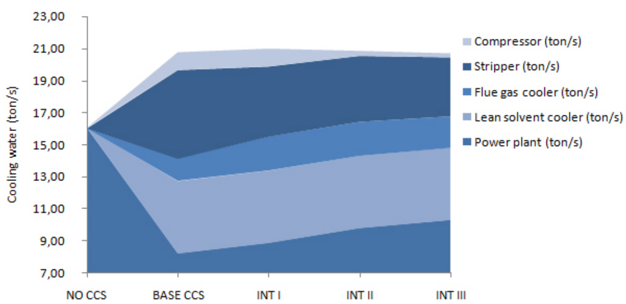

Figure 9.18: Cooling water requirements (ton/s) for the power plant after integration III. Design case

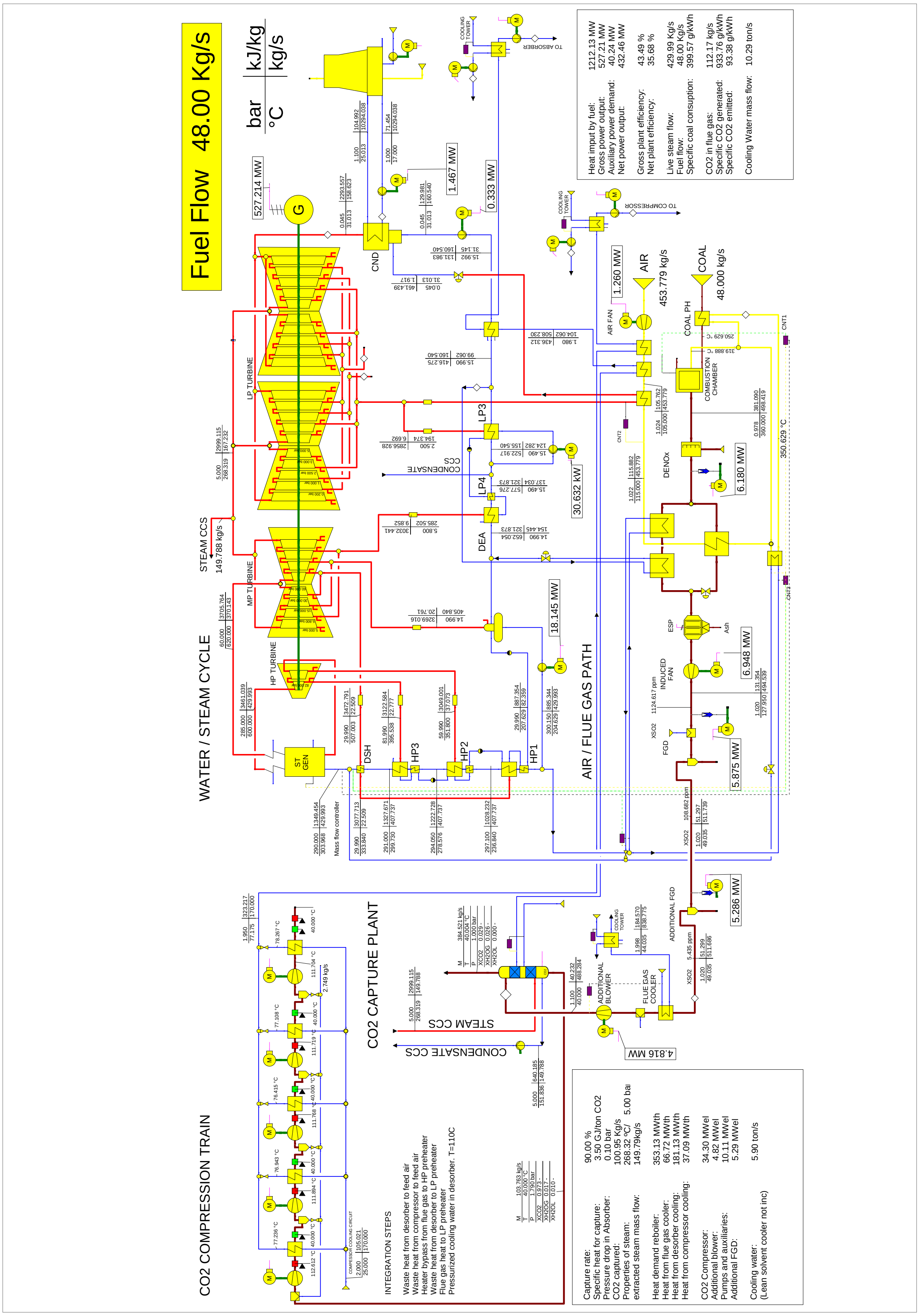

Figure 9.19: Complete model of the RPP NRW with integrated post-combustion capture plant (integration III) for design conditions, 48 kg/s coal mass flow.

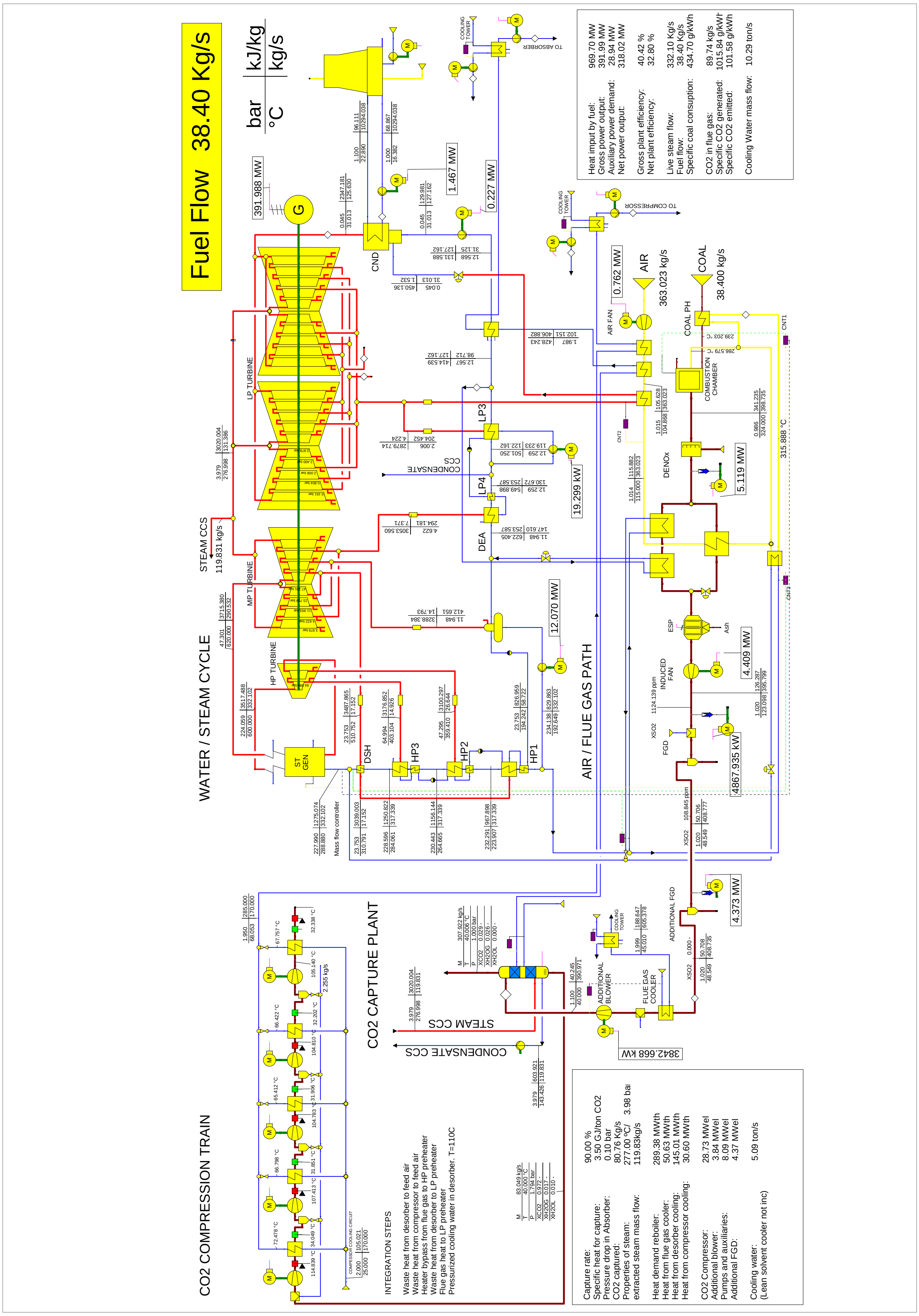

Figure 9.20: Complete model of the RPP NRW with integrated post-combustion capture plant (integration III) for 80% partload conditions, 34,8 kg/s coal mass flow.

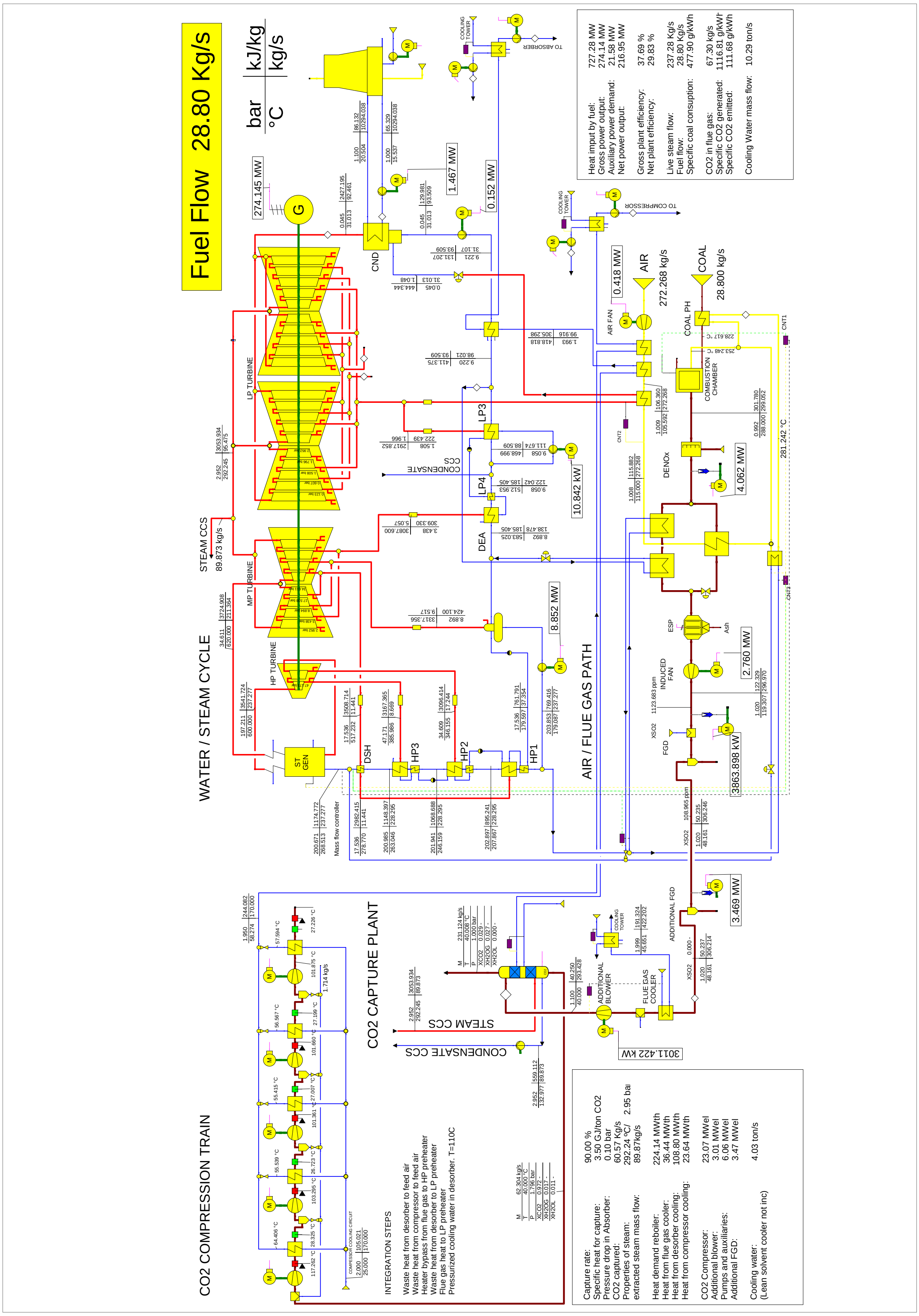

Figure 9.21: Complete model of the RPP NRW with integrated post-combustion capture plant (integration III) for 60% partload conditions, 28,8 kg/s coal mass flow.

9.6. Integration IV: Shockwave Compressor

Last three steps have covered all potential heat integration points within the low pressure feedwater line, high pressure feedwater line, and flue gas path. Further integration would require heat sources at higher temperatures. From this point of view, is not possible to increase more than 110°C cooling water at the desorber condenser, neither is possible in the flue gas cooler where cooling fluid temperature depends only on the flue gas temperature (above 50°C after the FGD plants). The compressor cooling water hot temperature is limited in state-of-art centrifugal compressors and increase it could damage the compression equipment or increase maintenance. However, one innovative compression technology, shockwave compression, promises high compression ratios up to 10+:1 and as a consequence CO_2 temperatures at the intercooling stages around 250°C. Section 3.9 describes briefly this novel technology from Ramgen®.

The model is displayed in figures 9.24, 9.25 and 9.26. Thermo-oil has been selected as cooling fluid to enable intercooling at high temperatures. The selected thermo-oil characteristics are included in the EBSILON® fluid database. This thermo-oil is the same used in parabolic trough solar collectors for concentrated solar thermal generation.

Once the model is operative, the optimal heat integration injections were pointed out. Despite thermo-oil temperature would allow heat transfer to the high pressure feedwater line, low pressure line heat integration shows better performance and achieves higher efficiencies. Thus, one first water-oil heat exchanger is located after LP4 to heat up the feedwater from 154°C to approximately 166°C. The oil leaves this first heat exchanger at 159°C and therefore is still able to transfer heat to the feedwater line or the air combustion preheating line. The optimal location was found between the waste heat recovery heat exchanger (integration II) and the water extraction to the flue gas (integration III). Thermo-oil leaves the second heat exchanger at 98°C. A third heat exchanger was proven to be not interesting since the power plant net efficiency improves less than 0,01% and the increase in complexity and initial investment do not balance such small efficiency improvement. Table 23 shows the key parameters and improvements of the retrofitted power plant. Net efficiency rises 0,2%. Despite the large amount of heat transferred to the water/steam cycle, effect of the electric consumption of the CO_2 compressor over the net output reduces heat integration impact.

	Unit	Base CCS	Integration IV	Variation
Gross power output	MW	509,76	535,07	+ 25,31
Net power output	MW	416,29	434,89	+ 18,60
Gross efficiency	%	42,06	44,14	+ 2,09
Net efficiency	%	34,34	35,88	+ 1,53

Table 23: Results of the simulation for integration IV. Design case, 48 kg/s coal mass flow

Compressor efficiency and heat integration EBSILON® default efficiencies have been selected for both compression stages in the model of the shockwave compressor due to the lack of detailed information (85% isentropic efficiency). However, we extract from literature that multi-gear centrifugal compressors could show better efficiency than the shockwave technology, according to [32] shockwave compressors could present efficiencies of below 70%.

At these conditions, electrical consumption increases from 39,65 MW_{el} to 48,14 MW_{el} and despite thermo-oil temperature rises up to 268°C, net efficiency drops to 35,41%[15]. Therefore, this tech-

[15] A simulation was run with 70% isentropic efficiency for the compressor and same location for the oil-water heat exchangers. While gross efficiency increased to 44,38% net plant efficiency dropped to 35,41%.

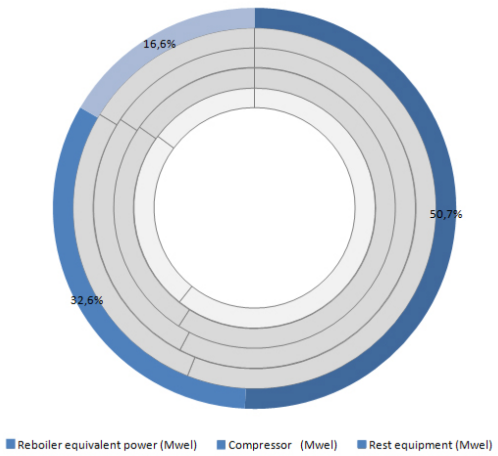

Figure 9.22: Relative energy consumptions for the different components of the integrated capture plant (INT IV) in design case, 48kg/s coal mass flow

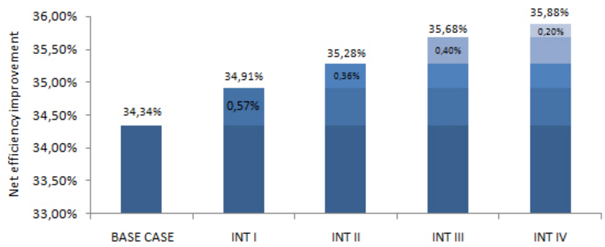

Figure 9.23: Net efficiency increase for the design case, 48 kg/s after heat integrations IV heat integration

nology would not be attractive from the efficiency point of view. Nevertheless, a trade off including other considerations such as initial investment, sizes or maintenance that are claimed to perform better with this novel technology could favour shockwave compressors.

Figure 9.22 represents as in last heat integration stages, the relative energy consumption of the different components in the capture plant. Thermal energy demand of the reboiler is expressed in power output drop in the generator. After analyzing impacts of the steam extraction on all consumer components of the power plant, the obtained value means a power equivalent factor (PeF) of 0,17 MW_{el}/MW_{th}. Nevertheless, it is important to state that for these calculations the positive effect that the waste heat of the compressor has on the power plant is taken into account as a reduction of the reboiler heat demand, with the consequent reduction of the PeF. To precisely assign positive impact of heat integrations distinguishing whether it comes from the capture process or the compression train would require a more exact analysis of the whole process. Despite this annotation, information extracted from the figure 9.22 is still representative and help us to a better understanding of the integrated capture plant performance after this optimization.

After this fourth integration step, net efficiency penalty decreases from 11,57% to 10,03%, which is a reduction of 13,3%. Significantly, for gross efficiency the penalty is reduced by more than 28%.

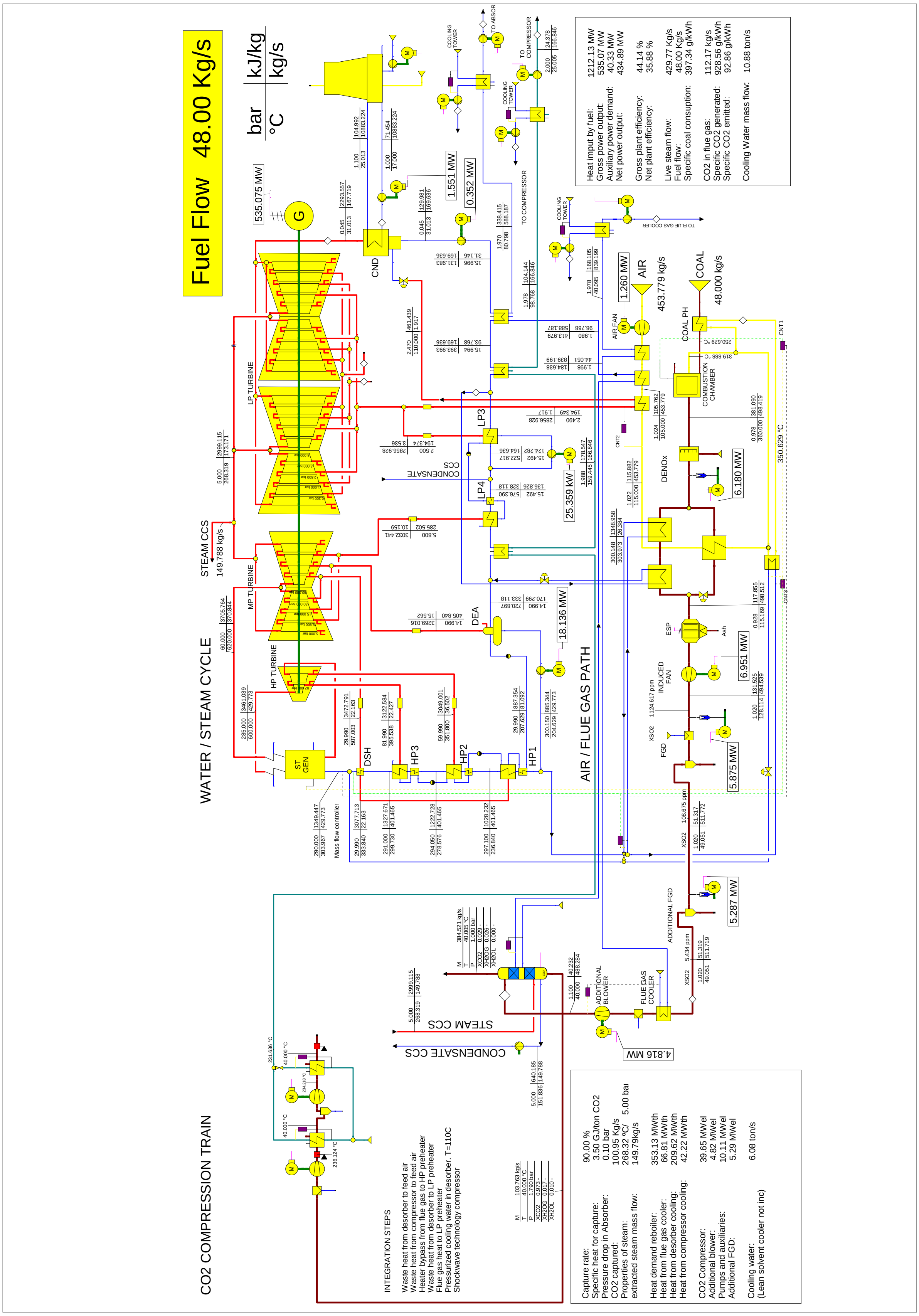

Figure 9.24: Complete model of the RPP NRW with integrated post-combustion capture plant (integration IV) for design conditions, 48 kg/s coal mass flow

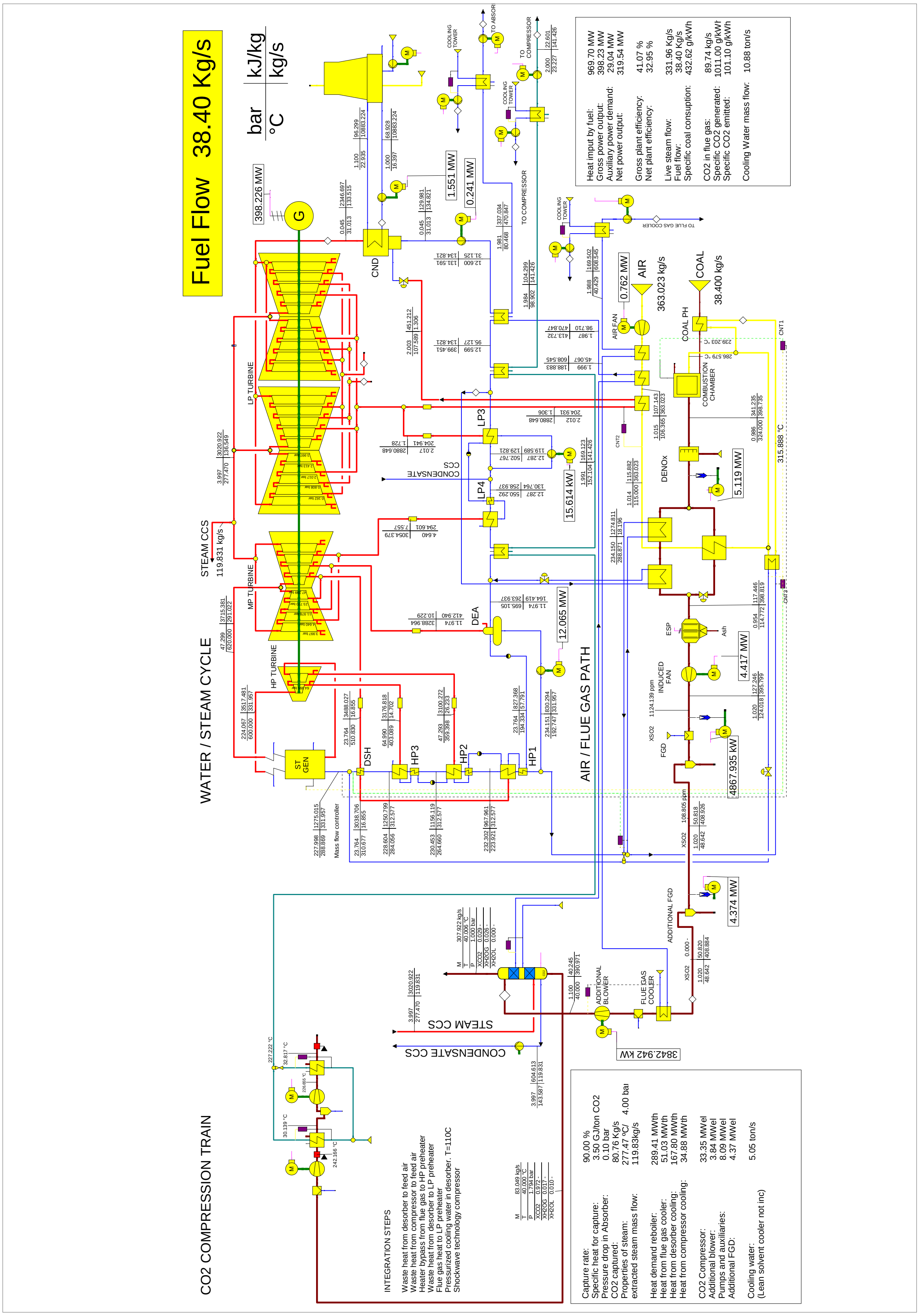

Figure 9.25: Complete model of the RPP NRW with integrated post-combustion capture plant (integration IV) for 80% partload conditions, 34,8 kg/s coal mass flow

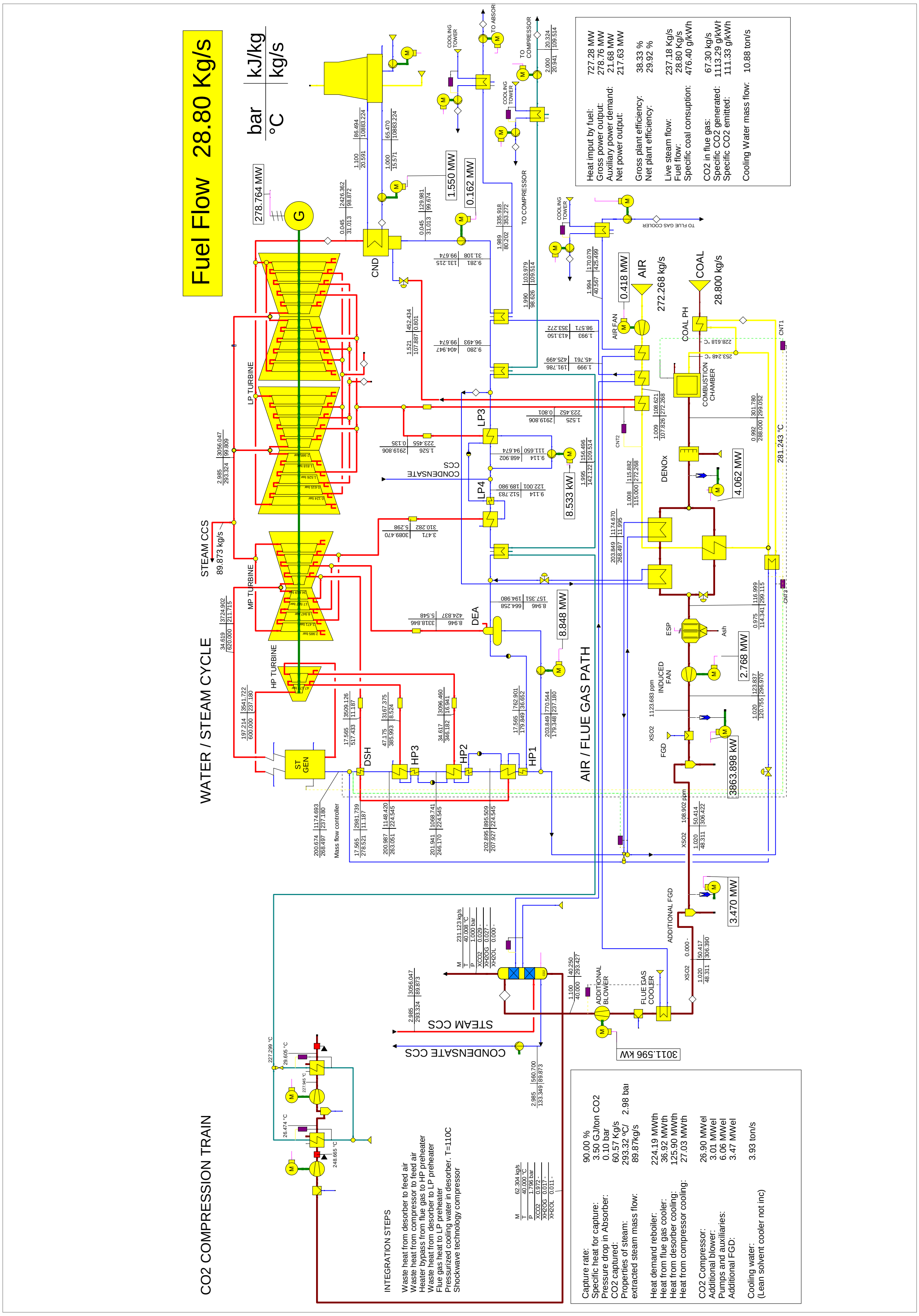

Figure 9.26: Complete model of the RPP NRW with integrated post-combustion capture plant (integration IV) for 60% partload conditions, 28,8 kg/s coal mass flow

9.7. Further Integrations

9.7.1. Integration V: Desuperheating Extracted Steam

The fact that the steam extracted from the IP/LP crossover pipe exceeds by much the minimum temperature limit imposed by the reboiler (in base load, is superheated steam at 268°C and 5 bar) allows the possibility for study a possible heat transference of the extracted steam before it enters the reboiler and with this, bring it over to saturated conditions. For this purpose a desuperheater was modeled in the steam pipe before enters the reboiler. The results of the simulation show an improvement of 0,12% in the net efficiency to reach 36% (see figures 9.27 and 9.28). Despite the steam mass flow required for regeneration increases from 149,7 kg/s to 158,9 kg/s, the positive preheating effect that the return of the condensate has on the feedwater preheating line is more significative. The condensate increases its temperature from 152°C to 183°C. Therefore, it has to be injected just before the deaerator and reduces significantly the steam bled for the deaerator. This reduction increases the power output of the IP turbine and not only balances the power loss in the LP turbine but supposes an improvement in the overall plant efficiency. Moreover, this heat integration would be easy to implement on the power plant since requires no modifications on the water steam cycle and the desuperheater could be located in the capture island. Together with this integration net efficiency penalty acumulated reduction is 14,3%, what represents a significant improvement for the retrofitted power plant.

Partload simulation Operation for 80% coal mass flow is correct and shows no simulation errors, neither warnings. In contrast, 60% partload resulted in the following error in the deaerator: *"Condensate inlet contains steam"*. This error is caused by the fall in pressures due to sliding pressure operation mode. Pressure in the deaerator, linked with the pressure of its steam bled coming from the IP turbine drops to 9 bar. This pressure corresponds to a saturation temperature of approximately 175°C, and the desuperheater is heating up the condensate from the capture plant to higher temperatures. LP feedwater preheating line overheats the feedwater in 60% part load (once more, we note that this partload corresponds to approximately 45% partload regarding to gross power output). However, this problem only appears when shockwave compressor is used. The simulation carried out for the installation of the desuperheater with a conventional compressor shown no partload errors and the net efficiency improvement was also 0,12%.

9.7.2. Capture Ready IP Turbine

Last optimization simulated was the implementation of a capture ready IP turbine like the one shown in figure 4.5. This turbine can add extra stages to increase expansion ratio and volume flow rate at the exhaust of the turbine. Therefore, steam conditions at the IP/LP crossover pipe would be lower (always over the limits imposed by solvent regeneration). One simulation was calculated for the supposed case when the IP turbine could increase its expansion ratio until steam conditions at the crossover IP/LP pipe were 3,1 bar, concluding with positive results; a net efficiency increase up to 36,57%, locating efficiency penalty below 9,4%. However, partload operation of the power plant would be impeded after this modification, since the sliding pressure operation mode leaves steam conditions under the limits for solvent regeneration for partloads below 85% of coal mass flow.

9.8. Final Results of the Optimization

The following section include graphics with acumulated results of all performed integrations (figures 9.29 to 9.36) including the fifth integration (section 9.7.1) but no section 9.7.2, for base load.

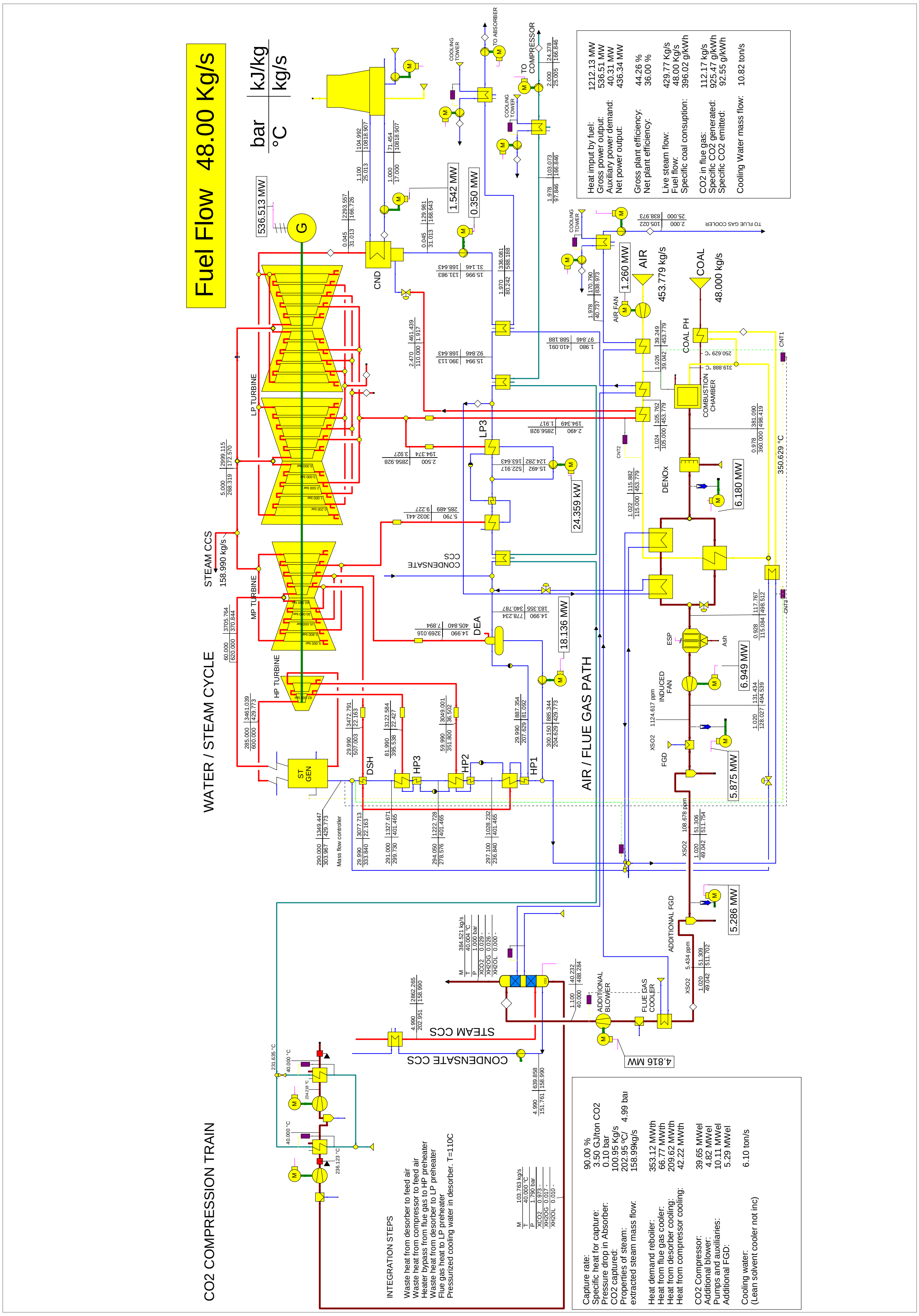

Figure 9.27: Complete model of the RPP NRW with integrated post-combustion capture plant (integration V) for base load conditions, 48 kg/s coal mass flow.

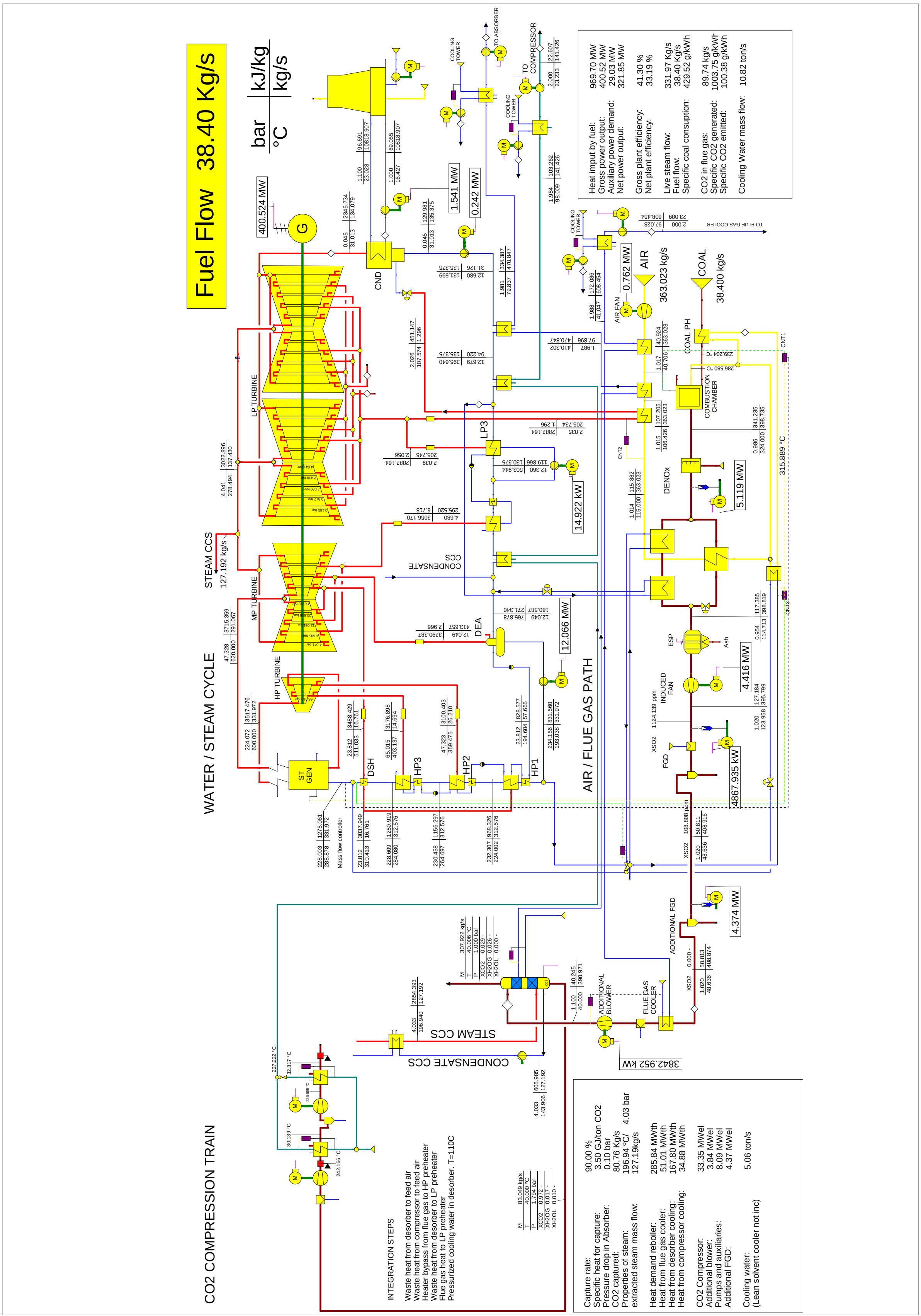

Figure 9.28: Complete model of the RPP NRW with integrated post-combustion capture plant (integration V) for 80% partload conditions, 38,4 kg/s coal mass flow.

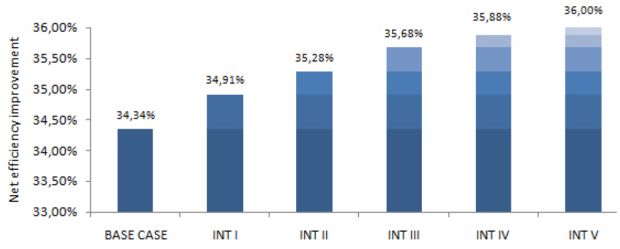

Figure 9.29: Net efficiency increase for the base load case after proposed optimizations

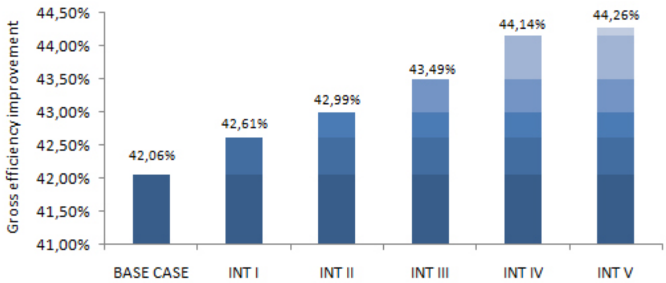

Figure 9.30: Gross efficiency increase for base load case after proposed optimizations

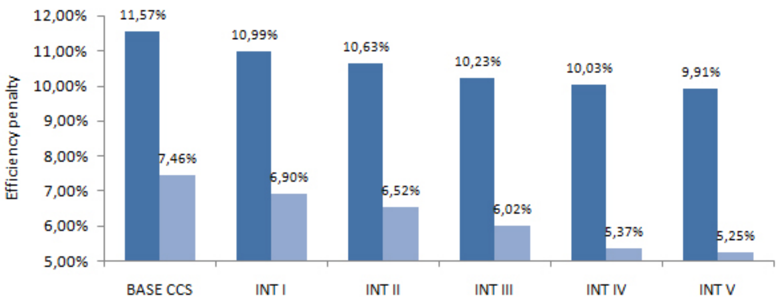

Figure 9.31: Gross and Net (dark blue) efficiency penalty for proposed integrations. Base load

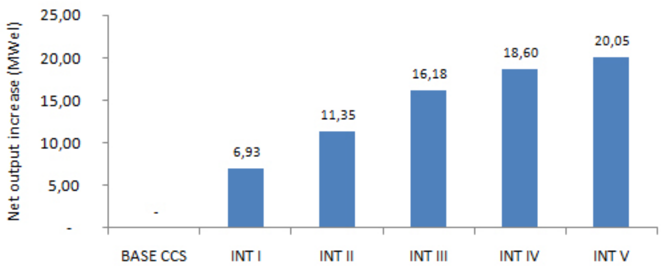

Figure 9.32: Net power output increase after proposed optimizations. Base load

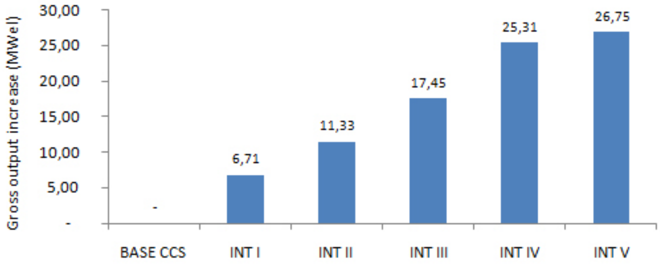

Figure 9.33: Gross power output increase after proposed optimizations. Base load

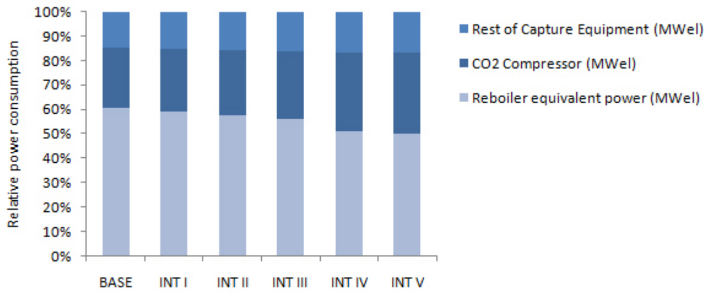

Figure 9.34: Relative power consumption of the different elements from the capture plant. Base load

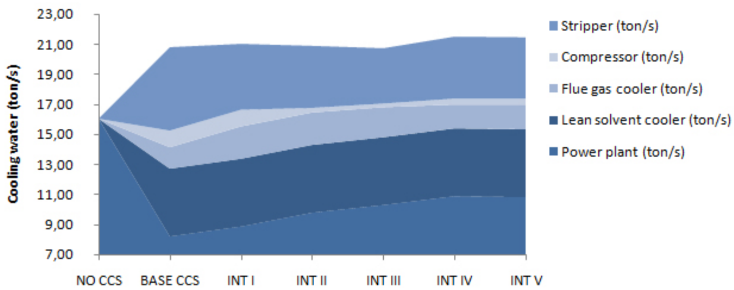

Figure 9.35: Cooling water requirements after proposed integrations. Base load

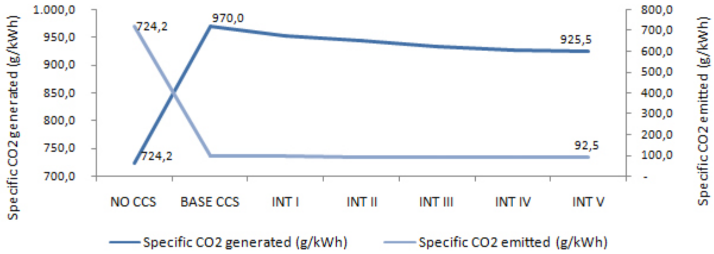

Figure 9.36: Specific emissions for the Reference Power Plant NRW. Base load

10. Conclusions and Outlook

At present, post-combustion capture is a leading technology within CCS but it still faces two main technical challenges prior to become commercially viable; to scale-up, and a significant reduction of energy expenditure. In order to minimize energy consumption, a double approach needs to be followed; first, capture process optimization by the implementation of new improved flowsheets, less energy intensive solvents for the capture process and optimal operating conditions; second, heat integration between capture and power plant. This thesis seeks to analyze the potential of heat integration and its effect towards efficiency and performance of the retrofitted power plant. With this target, a series of simulations were carried out with the software EBSILON® Professional to find out what further opportunity exists to reduce impact on the net output via astute integration of both plants.

When the post-combustion capture plant is installed, specific emissions are reduced by 87% but heat requirements for solvent regeneration and electric consumption of the compressor and auxiliary equipment cause a drop in net power output of 140 MW_{el} and a net efficiency penalty of 11,6% points. The simulation demonstrated how almost a 15% reduction on the net power efficiency penalty can be achieved by heat integration, reaching net efficiency penalties of 9,9% points. This means an increase in net power output of more than 20 MW_{el} compared to the base CCS case. However, high integration entails modifications in the LP feedwater line, flue gas path and additional heat exchangers and cooling water circuit. In this study, up to eight heat exchangers were implemented to reach the mentioned improvement. As future work, a energy-economic balance would need to be addressed in order to analyze effectiveness of heat integration in reducing post-combustion capture capital and operational costs.

The capture plant rejects large amounts of low quality heat that require an increase in cooling water requirements. Heat integration reduces waste heat of the capture plant but raises condenser duty in the water/steam cycle. Both effects were found to be of the same magnitude and therefore, cooling water requirements remain stable around 30% higher with and without integration.

85% of the total energy consumption within the capture plant is due to solvent regeneration and CO_2 compression. Thus, heat from the CO_2-water cooler/condenser at the top of the desorber, together with the CO_2 compressor intercooling showed the highest potential for plant integration. Reaching the highest temperatures in the cooling system for these two sources enables further integration. Temperatures in the stripper depend strongly on the type of solvent; for the basic MEA solution simulated within this thesis a temperature limit of 110°C was analyzed. The re-use of these heat sources leads to reductions in power equivalent factor (PeF) for the reboiler from 0,24 to 0,17 MW_{el}/MW_{th}. In this search of higher temperatures for integration, the novel shockwave compression technology was analyzed. This technology showed substantial improvement increasing the gross output of the retrofitted power plant around 8 MW_{el}. Nevertheless high electrical consumption cuts this improvement to 2,5 MW_{el} in net output. Hence, compressor isentropic efficiency was proven to be a crucial factor since below 78% the shockwave compressor model showed no net efficiency improvement.

Post-combustion technology is not commercially viable yet, but new projects are scaling-up this technology and CCS demonstration by 2015 is now feasible. With regard to the second challenge, post-combustion shows high potential to reduce energy consumption by both process optimization and heat integration. From this study we learnt that heat integration depends strongly on the solvent properties, for this reason the new fleet of power plants should be built capture-ready avoiding lock-ins which could obstruct the expected future developments of this promising technology.

List of Figures

List of Tables

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A. APPENDIX I: Capture Plant EbsScript Model

The capture plant was simulated as a "black box", by the use of one EbsScript which models the behavior of the real capture process. Since the aim of this thesis was heat integration between the capture and power plant. All relevant heat sources have been modeled (see section 9.1) whether within the macro object or as an external component.

Figure A.1 shows the model for the capture plant with three different sections: first one in the center, the CO_2 Washer EbsScript. Upstream the flue gas is the flue gas cooler, modeled outside the EbsScript for simplicity. Finally, at the right side the desorber cooling system, an intermediate system cools down the CO_2 cooler / stripping steam condenser and transfers its heat to the main cooling circuit coming from and directed to the wet cooling tower.

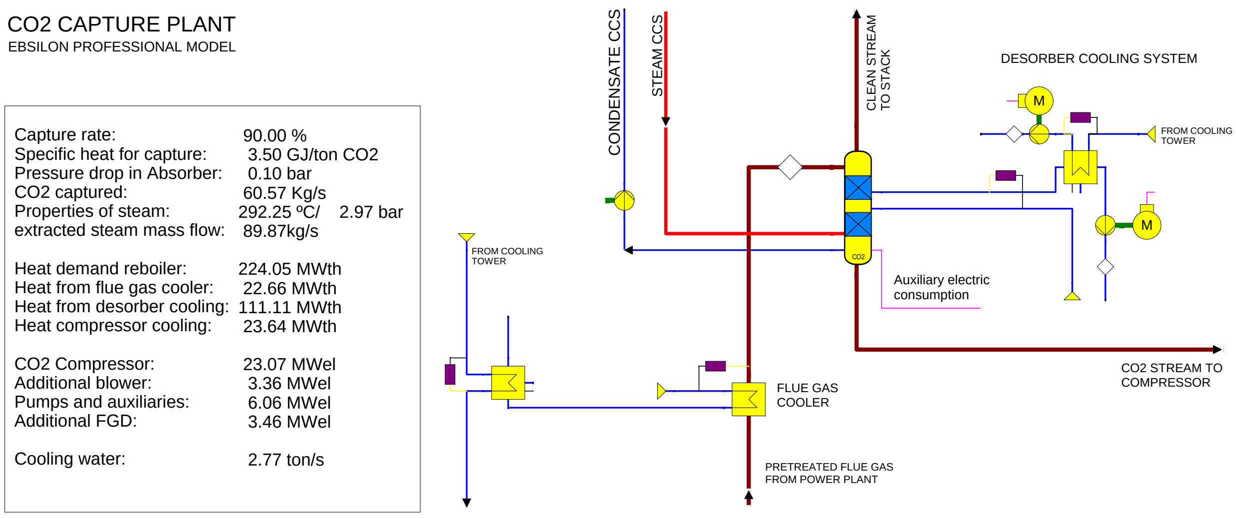

Figure A.1: EBSILON® Model for the simulated post-combustion capture plant

Within the *CO_2 Washer*, all relevant heat sources energy consumption and mass flows have been simulated. Figure A.2 displays the programmed EbsScript *CO_2 Washer*.

CO2 Separation This section consists of one *Splitter* (comp 52) two *Value transmitters* (comp 36) and a *Start Value* (comp 3). CO_2 is separated in the *Splitter* from the inlet stream of the pretreated flue gas. To do so, the ebsscript inserts the separation ratio (JCO2) scheduled by the user in the CO_2 Washer properties. In this component some water separation can be also set to simulate the real amount of water leaving with the cleaned stream and with the CO_2 flux to the compressor.

Desorber pressure and temperature were considered constant parameters for this study. The *Start value* (comp 3) present in the CO_2 separation section dictates $P_{desorber}$ =1,8 bar $T_{desorber}$ = 120°C. The rest of information from the separated stream is transferred by the *Value transmitters* (composition in pink and mass flow in white) to a flue gas pipe. Once transmitted all mentioned information, the CO_2 flux behaves like the CO_2 stream leaving the desorber and before entering the CO_2 cooler. However, in the real process this stream leaves together with stripping steam that will be condensed in the CO_2 cooler.

Desorber CO2 Cooler/Condenser The heat evacuated in the CO_2 cooler is the sum of two heat sources: first, the condensing and subcooling of the stripping steam and second the CO_2 flux being cooled to 40°C.

Since EBSILON® is not the preferred option to simulate chemical processes within the absorption and desorption column. The amount of stripping steam condensing in the CO_2 cooler is modeled by the use of a *Reflux ratio* (R_{reflux}). This value (see section 8.1) is set in the *Calculator* (comp 77) with a constant value of 0,6 ton H_2O per ton of CO_2. Thus, to obtain the amount of stripping steam condensing in the CO_2 cooler, it is only necessary to calculate the separated CO_2 mass flow. This operation is carried out by the *Calculator* once the *Start value* (comp 3) contains the CO_2 mass fraction in the pretreated flue gas (EbsScript automatically assign the mass fraction to the start value). Calculator follows the next equation:

$$\dot{m}_{sripping,st} = X_{\mathrm{CO}_2} \cdot JCO2 \cdot \dot{m}_{fluegas} \cdot R_{reflux} \tag{A.1}$$

According to the real process, the stripping steam has the same temperature and pressure than the CO_2 since both leave together the desorption column. Therefore, two *Value transmitters* (pressure in red and temperature in green) dictate the steam conditions. Comp 13, a *Heat consumer*, is set to condensate the steam mass flow entering, and to sub cool it up to the same temperature than the separated CO_2 stream (set by a temperature *Value transmitter*). This is the temperature which with the CO_2 flue gas and condensate leave the cooler. The heat transferred from cooling the CO_2 flux from 120°C to 40°C is modeled with a *Universal heat exchanger* (comp 55).

Two logic components, *Difference meters* (comp 30) calculate the enthalpy difference of CO_2 flue gas before and after the cooler and the stripping steam before and after the *Heat consumer*. Obtained values are introduced in the *Power summarizer* (comp 31) where the output is the total heat to be transferred. This value is the input of a *Heat injection* (comp 16) which heats up the cooling water the exact amount transferred previously by steam and CO_2 streams.

Reboiler Heat Consumption Heat requirement for solvent regeneration is provided by steam from the IP/LP crossover pipe. To model the total heat needed the parameter specific heat demand in reboiler (QSOLV) is used. This parameter is set by the user in the properties window of the *CO_2 washer*. In an analogous way than in the CO_2 cooler, the required inputs: CO_2 mass flow, specific heat demand and enthalpy values of the extracted steam and condensate are operated in the EbsScript to obtain the required steam mass flow per kg CO_2 following the next equation:

$$\dot{m}_{steam} = \frac{X_{\mathrm{CO}_2} \cdot JCO2 \cdot QSOLV}{h_{steam} - h_{cond}} \cdot \dot{m}_{fluegas} \tag{A.2}$$

The heat consumer is set to condensate all steam mass flow previously obtained up to saturated water.

Pumps and Auxiliaries Consumption The specific amount of electric energy per kg CO_2 is a predefined value that can be obtained from cited literature. In the same way, the calculator returns the corresponding electric consumption for the flue gas entering the EbsScript following the next equation.

$$Q_{el} = X_{\mathrm{CO_2}} \cdot JCO2 \cdot \dot{m}_{fluegas} \cdot Q4N \tag{A.3}$$

Pressure Drop in the Absorber Pressure drop (DP) is set by the user. A *Throttle* (comp 2) reduces pressure simulating the pressure drop caused in the absorption column. After a isoenthalpic expansion gas temperature decrease. To simulate the exact conditions which with the cleaned flue gas leaves the capture plant, a *Heat injection* (comp 16) heats up the stream directed by a controller (CNT1) that calculates the exact amount of heat to be injected to reach a temperature in the cleaned stream equal to the flue gas entering the absorber and hence keeping constant the water balance.

Source Code for the Programmed EbsScript All calculations and formulas are inserted in the source code of the user defined EbsScript. The following code is responsible for the operation of the components described above.

```
begin
    if (MacroInterface.FSPEC = 0) then
    begin
        Splitter.FM:=2;
        Splitter.JCO2:=MacroInterface.JCO2;
    end
    else if (MacroInterface.FSPEC = 1) then
    begin
        Splitter.FM:=-1;
    end;
    Throttle.DP12RN:=MacroInterface.DP;
    Start_value.M:=(CO2_mass_frac.RESULT*MacroInterface.JCO2*MacroInterface.QSOLVN)/(Heat_cons.H1N-Heat_cons.H2N);
    Start_value_1.H:=(CO2_mass_frac.RESULT*MacroInterface.JCO2*MacroInterface.Q4N);
    Start_value_3.M:=(CO2_mass_frac.RESULT);

end.
```

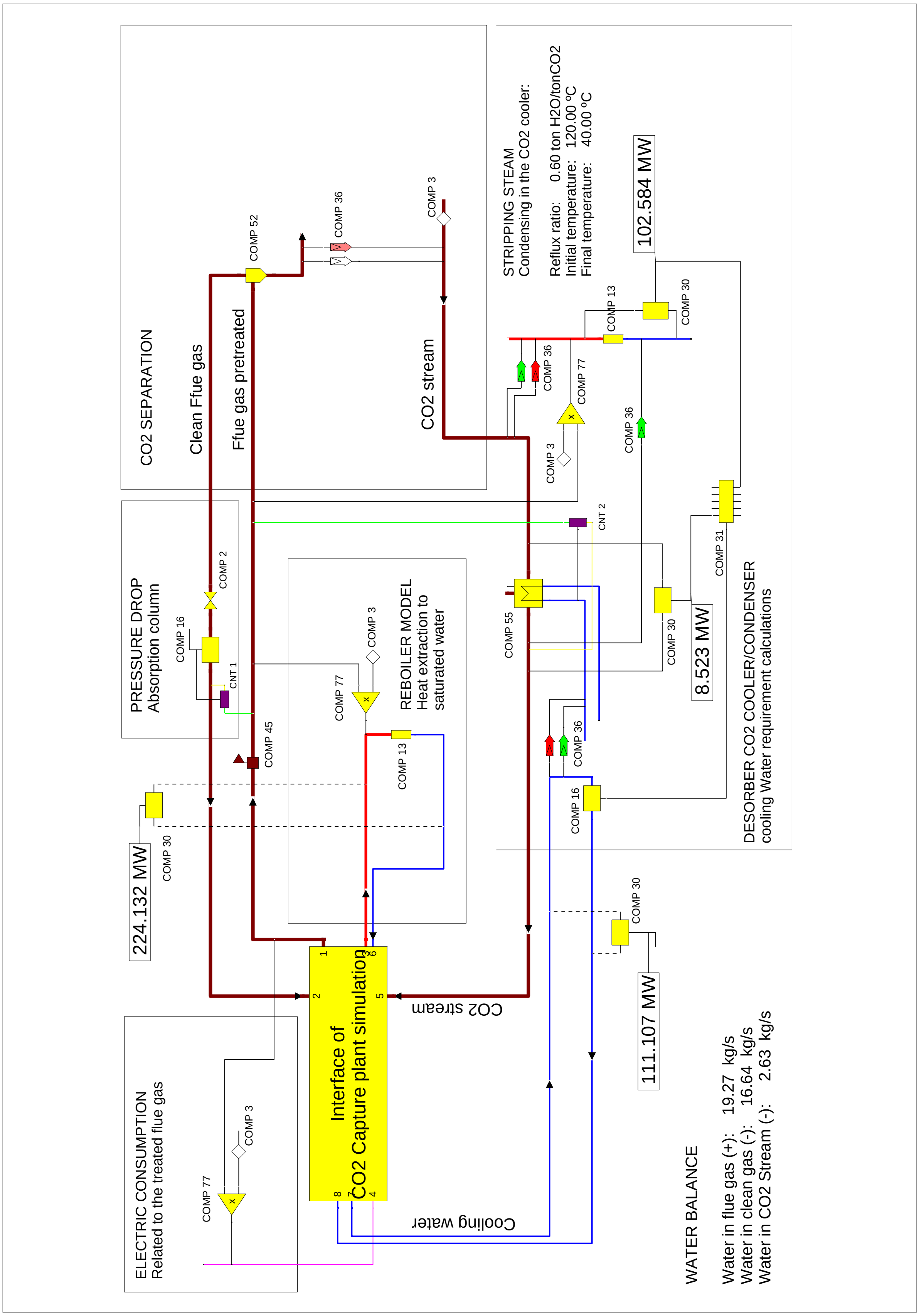

Figure A.2: Macro interface of the modeled capture plant